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Hon. Lisa Jackson, Administrator
U.S. Environmental Protection Agency Headquarters
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Mail Code: 1101A
Washington, D.C. 20460

Via Certified Mail, Return Receipt Requested, and electronic mail (jackson.lisa@epa.gov)

Re: Petition to Add the Oil and Gas Extraction Industry, Standard Industrial Classification Code 13, to the List of Facilities Required to Report under the Toxics Release Inventory

Dear Administrator Jackson:

Pursuant to section 313(b)(1)(B) of the Emergency Planning and Community Right-to-Know Act ("EPCRA") and section 553(e) of the Administrative Procedure Act, the Environmental Integrity Project, Chesapeake Climate Action Network, CitizenShale, Clean Air Council, Clean Water Action, Delaware Riverkeeper Network, Earthworks, Elected Officials to Protect New York, Environmental Advocates of New York, Lower Susquehanna Riverkeeper, Natural Resources Defense Council, OMB Watch, PennEnvironment, Powder River Basin Resource Council, San Juan Citizens Alliance, Sierra Club, and Texas Campaign for the Environment (collectively "Petitioners") hereby petition the Environmental Protection Agency ("EPA") to initiate rulemaking to add the Oil and Gas Extraction Industry, identified by Standard Industrial Classification Code 13 ("SIC Code 13") and various North American Industry Classification System ("NAICS") codes,¹ to the list of facilities required to report releases of toxic chemicals listed under the Toxics Release Inventory ("TRI") of EPCRA.

¹ When EPA last considered addition of the industry in 1996, it identified it by SIC Code 13. See *Addition of Facilities in Certain Industry Sectors; Toxic Chemical Release Reporting; Community Right-to-Know*, 61 Fed. Reg. 33,588, 33,592 (June 27, 1996). Since then, the NAICS codes have begun to supplant SIC codes, and the oil and gas extraction industry is also identified by at least seven NAICS codes: 211111 (Crude Petroleum and Natural Gas Extraction), 211112 (Natural Gas Liquid Extraction), 213111 (Drilling Oil and Gas Wells), 213112 (Support Activities for Oil and Gas Operations), 213112 (Support Activities for Oil and Gas Operations), 238910 (Site Preparation Contractors), and 541360 (Geophysical Surveying and Mapping Services). See NAICS Ass'n, *Free NAICS Look Up*, <http://www.naics.com/search.htm>. EPA noted this in 2000, identifying six NAICS codes for the industry. EPA, *Office of Compliance Sector Notebook Project: Profile of the Oil and Gas Extraction Industry 4* (Oct. 2000) [hereafter *Industry Sector Profile*], available at <http://www.epa.gov/compliance/resources/publications/assistance/sectors/notebooks/oilgas.pdf>.

In the last decade alone, the number of wells, storage tanks, production, and processing facilities within the oil and gas extraction industry has increased dramatically, and the variety of toxic chemicals manufactured, processed, or otherwise used by the industry has expanded significantly.² Meanwhile, public information about the use and releases of these chemicals remains scant, given that federal and state disclosure requirements are extremely limited, full of gaps and exemptions, and have not kept pace with these industry expansions.

EPA recently estimated that oil and gas extraction operations release nearly 130,000 tons of hazardous air pollutants every year, equivalent to thirty percent of the total released by all industries that report their emissions to the Toxics Release Inventory today, and more than any other sector except power plants. EPA's recent onsite investigations have found significant releases to groundwater: in Pavillion, Wyoming, samples included synthetic toxic chemicals that could be linked directly to natural gas production uses and benzene forty-nine times above the drinking water MCL; and in Dimock, Pennsylvania, samples detected TRI-listed chemicals in every single drinking water well, including forty-six different chemicals, and with an average of twenty detections per well. Surface water releases are also significant, as wastewater treatment plants are unable to remove radioactive materials and bromide salts, the latter of which may react to form toxic trihalomethanes when processed by drinking water treatment facilities. And the industry's informational and regulatory gaps are becoming apparent with respect to land disposal, as landfills are encountering increasing shipments of hazardous, radioactive, and unknown wastes.

The communities that host this rapidly growing industry have the right to know what is being released to their environment. There is little question that the oil and gas extraction industry should be reporting its releases, as chemical manufacturers, power plants, refineries, and other sectors have had to do for many years.

As explained in detail below, it is clear that EPA has the legal authority to require the oil and gas extraction industry to report its releases to the TRI, based on statutory provisions under section 313 of EPCRA, and that the industry readily meets EPA's three factors for addition of a new industrial sector to the TRI.

Petitioners request that EPA add all NAICS code necessary to fully encompass the oil and gas extraction industry within the TRI reporting system.

² As discussed in further detail below, the oil and gas extraction industry includes well exploration and development, such as drilling and hydraulic fracturing; natural gas processing, such as dehydration and sweetening; well abandonment; and associated components that are used throughout the industry, such as waste pits, storage tanks, and compressors. *See, e.g.,* Part II, *infra*; *Industry Sector Profile* at 15; EPA, *Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry* 2-1 (April 2012) [hereafter *RIA*].

PETITIONERS

The Environmental Integrity Project (“EIP”) is a nonpartisan, nonprofit organization established in 2002 by former EPA enforcement attorneys to promote more effective enforcement of federal environmental laws. EIP has three goals: (1) to provide objective analyses of how the failure to enforce or implement environmental laws increases pollution and affects public health; (2) to hold federal and state agencies, as well as individual corporations, accountable for failing to enforce or comply with environmental laws; and (3) to help local communities obtain the protection of environmental laws.

The Chesapeake Climate Action Network (“CCAN”) is a regional, grassroots, non-profit organization representing over 90,000 members in Washington, D.C., Maryland and Virginia. CCAN was founded to transition the mid-Atlantic region towards clean energy solutions to climate change. CCAN’s mission is to educate and mobilize citizens in a way that fosters a rapid societal switch to clean energy sources and away from fossil fuel-based energy production and extraction activities that contribute to global warming. This mission includes ensuring that dangerous energy extraction activities, such as natural gas hydraulic fracturing (or “fracking”), do not impact the health and safety of their members who reside in the Marcellus Shale regions of Maryland and Virginia. As one method of achieving this mission, CCAN participates in environmental permit proceedings of oil and gas drilling activities at the state level, to ensure compliance with federal and state environmental pollution laws.

CitizenShale works through research, policy review, and education to encourage dialogue and support comprehensive efforts to protect individuals and communities from the wide-ranging impacts of shale gas development. CitizenShale’s goals include: reviewing and supporting national, state, and local policies that guarantee strong, enforceable regulations and rights to health, safety, and property; educating and informing citizens in Maryland and the region; and providing tools for individuals and communities to engage in political, regulatory, monitoring, and assessment processes associated with shale gas production. By partnering with government, businesses, foundations and community groups, Citizen Shale will develop mechanisms for citizen input and local control.

Clean Air Council is a member-supported environmental organization serving the Mid-Atlantic Region. The Council is dedicated to protecting and defending everyone’s right to breathe clean air. The Council works through a broad array of related sustainability and public health initiatives, using public education, community action, government oversight, and enforcement of environmental laws.

Clean Water Action is a one-million-member organization working to protect our environment, health, economic well-being and community quality of life. Organizational goals include clean, safe and affordable water; prevention of health threatening pollution; creation of environmentally safe jobs and businesses; and empowerment of people to make democracy work. Clean Water Action is working to repeal exemptions for shale gas drilling and adopt new federal rules to ensure that it does not pollute our air and water. Clean Water Action is also working on the state level in Michigan, Maryland, New Jersey and Pennsylvania to promote

moratoriums on new drilling until there are safeguards in place to protect water and air, and in Colorado and Texas to strengthen the rules that protect our water.

The Delaware Riverkeeper Network (“DRN”) is the only environmental organization working throughout the four-state watershed of the Delaware River: New York, New Jersey, Pennsylvania, and Delaware. DRN has been involved in natural gas drilling and fracking issues since 2008, when leases of mineral rights began to be signed by landowners in the Upper Delaware River Watershed where the Marcellus shale formation is located. Although natural gas drilling has not yet begun in the Basin, gas-related infrastructure and related facilities already affect the Basin, such as water withdrawals for hydraulic fracturing, pipelines, compressor stations, gas processing and storage facilities, wastewater processing and discharge and waste disposal or storage facilities, and liquefied natural gas plants. DRN works on natural gas development at the federal, regional, state, and local levels, including community education and organization, extensive advocacy to legislators and agency decision-makers, and litigation in federal and state courts.

Earthworks is a nonprofit organization dedicated to protecting communities and the environment from the impacts of irresponsible mineral and energy development while seeking sustainable solutions. We fulfill our mission by working with communities and grassroots groups to reform government policies, improve corporate practices, influence investment decisions and encourage responsible materials sourcing and consumption.

Elected Officials to Protect New York is a nonpartisan, geographically-diverse group of 442 local elected officials, representing cities, towns, villages, and counties across New York, who are committed to protecting their great state. In particular, these officials are concerned about the potential impacts of hydraulic fracturing and related drilling operations on the health, welfare, and economies of the communities they represent and have called on Governor Cuomo to continue New York State’s moratorium on fracking until the drilling method is proven safe for all New Yorkers.

Environmental Advocates of New York’s mission is to protect our air, land, water and wildlife and the health of all New Yorkers. Based in Albany, we monitor state government, evaluate proposed laws, and champion policies and practices that will ensure the responsible stewardship of our shared environment. We work to support and strengthen the efforts of New York’s environmental community and to make our state a national leader.

Lower Susquehanna Riverkeeper, a program of Stewards of the Lower Susquehanna, Inc., is dedicated to protecting and improving the ecological integrity of the Susquehanna Watershed and Chesapeake Bay. Lower Susquehanna Riverkeeper represents friends, neighbors, outdoorsman, recreationalists and families in Pennsylvania and Maryland who want safe drinking water, sustainable use of natural resources, and the ability to fish and swim in the Susquehanna River and her tributaries. Towards this end, Lower Susquehanna Riverkeeper acts as the citizen watchdog for the Susquehanna, identifying pollution threats and engaging decision-makers to ensure that community health and the environment is properly protected, and that best available science guides environmental regulation.

The Natural Resources Defense Council ("NRDC") is a nonprofit environmental action group established in 1970 by a group of law students and attorneys at the forefront of the environmental movement. NRDC's purpose is to safeguard the Earth: its people, its plants and animals and the natural systems on which all life depends. NRDC uses law, science and the support of 1.2 million members and online activists to protect the planet's wildlife and wild places and to ensure a safe and healthy environment for all living things. NRDC has worked for many years to ensure the proper regulation of oil and gas exploration and production operations.

OMB Watch is a nonprofit research and advocacy organization dedicated to building an open, accountable government that invests in the common good, protects people and the environment, and advances national priorities defined by an active, informed citizenry. OMB Watch has long worked on issues surrounding the Toxics Release Inventory and more broadly the public right to know. In its first decade, OMB Watch organized a coalition focused on the implementation of EPCRA, required EPA to make TRI data available through "computer telecommunications and other means." Over the years, the organization has been a constant advocate to maintain and even expand the TRI program, most notably organizing strong public interest opposition to rulemakings that sought to significantly rollback reporting requirements. Most recently, OMB Watch has studied the varying successes and shortcomings of state fracking disclosure rules.

PennEnvironment, Inc. is a nonprofit, citizen-based environmental advocacy organization that advocates for clean air, clean water and the protection of open spaces across Pennsylvania. Since 2002, PennEnvironment has worked to identify environmental problems facing the commonwealth and has advocated pragmatic solutions, often with the help of its 110,000 citizen members and activists. In response to shale gas development, PennEnvironment has become as strong voice in favor of greater protection of Pennsylvania's environment, and its residents' health and quality of life. One of PennEnvironment's top priorities has been addressing the environmental and public health threats from Marcellus Shale gas drilling. This work has included releasing multiple research reports on the issue of gas drilling, garnering hundreds of news stories on the environmental effects of gas drilling, distributing educational materials to hundreds of thousands of Pennsylvanians, and advocating strong policy protections to state, regional, and federal elected officials.

Powder River Basin Resource Council ("PRBRC") strives to ensure the preservation and enrichment of Wyoming's agricultural heritage and rural lifestyle. PRBRC believes in the conservation and responsible use of Wyoming's unique land, mineral, water and clean air resources to sustain the livelihood of present and future generations. As an organization, PRBRC works to empower individuals through community organizing and leadership development to raise a coherent and effective voice in decisions that will impact their lifestyle.

The San Juan Citizens Alliance ("SJCA") is a grassroots organization dedicated to social, economic and environmental justice. SJCA organizes San Juan Basin residents to protect the Basin's water and air, public lands, rural character, and unique quality of life while embracing the diversity of the region's people, economy, and ecology.

The Sierra Club runs national advocacy and organizing campaigns dedicated to reducing American dependence on fossil fuels, including natural gas, and to protecting public health. These campaigns, including its Beyond Coal campaign, and its Natural Gas Reform campaign, are dedicated towards promoting a swift transition away from fossil fuels and to reducing the impacts of any remaining natural gas extraction. Sierra Club members throughout the country live in and around areas in which development of shale gas formations is occurring or proposed. The Club's Pennsylvania and Maryland Chapters in particular focus many of their advocacy efforts on gas issues, and are deeply engaged in permitting and regulatory processes.

Texas Campaign for the Environment ("TCE") is a nonpartisan, nonprofit citizens' organization dedicated to informing and mobilizing Texans to protect the quality of their lives, their health, their communities and the environment. TCE works to hold government and businesses accountable to public concern on Texas health, environmental, and economic issues. TCE promotes policies that ensure clean air and clean water, while encouraging recycling and the reduction of waste. And TCE protects citizens' right to know about pollution in their communities.

EXECUTIVE SUMMARY

The Toxics Release Inventory was enacted in 1986 as a response to the Bhopal disaster that exposed hundreds of thousands of people to toxic chemicals. Since then, it has served as a simple but vital public guide to the toxic chemicals used by industrial facilities and released to the air, land, and water. While the TRI does not contain substantive pollution controls like other federal environmental laws and provisions, the information it requires to be reported serves two critical goals: encouraging informed community-based environmental decision making, and providing an incentive for industrial sectors to reduce or prevent pollution. To further these goals, the TRI requires certain industrial sectors to file annual reports of the amounts of toxic chemicals released to the environment, or recycled, treated, or disposed of in impoundments and landfills. These disclosures are published in the Inventory, are available online, and provide basic information about the environmental "footprint" of facilities.

The TRI as originally established by Congress only included facilities in the manufacturing sectors, but Congress also vested in EPA the authority to add new industry groups as the agency saw fit. President Clinton recognized the importance of this authority and made it a priority for EPA to add many more sectors in order to expand the reach of the TRI, increase the information provided to the public, and provide further incentive to the sectors to use less toxic chemicals. As EPA has acknowledged, "[t]he initial list of chemicals and facilities identified in the original [EPCRA] legislation was meant as a starting point," and "Congress recognized that the TRI program would need to evolve to meet the information needs of a better informed public and to fill information gaps that would become more apparent over time."

In exercising this authority, EPA has articulated three primary factors it considers: (1) whether TRI-listed chemicals are reasonably anticipated to be present at facilities in the candidate industry group (the "chemical" factor); (2) whether facilities manufacture, process, or otherwise use these chemicals (the "activity" factor); and (3) whether facilities can reasonably be

anticipated to increase the information made available pursuant to the TRI or otherwise further its purposes (the “information” factor).

In 1996 and 1997, EPA exercised this authority and issued a final rule adding several additional sectors to the TRI list of facilities—including resource-extraction sectors such as metal mining and coal mining. Although EPA had considered the oil and gas extraction industry as a “primary candidate” for addition, due to its significant use of TRI-listed chemicals, it ultimately chose not to put the sector forward, deferring it for reconsideration “at a later date.” EPA made this decision solely because of technical questions in defining facilities for reporting.

The oil and gas extraction sector involves a variety of processes using scores of TRI-listed chemicals in large quantities and releases such chemicals into air, water, land, and other environmental media. Specifically, well exploration and development use and release millions of gallons of muds, fluids, and additives to drill and stimulate production of oil and natural gas; generate and landfill tons of solid wastes such as drill cuttings; and emit tons of air pollutants with each well completion. Natural gas processing uses a variety of toxic chemicals to remove toxic impurities from the fuel stream and releases these chemicals and byproducts to the air and other environmental media. And regular venting, flaring, and fugitive emissions are endemic to the sector and regularly emit tons of hazardous air pollutants (“HAPs”) such as benzene to the air. The risks associated with these releases have only increased in recent years with the advent of the process of horizontal hydraulic fracturing, which allows for the production of more wells and more natural gas, uses vastly greater amounts and volumes of chemicals, produces more wastes, and has allowed for a much bigger industry.

It is clear that the industry meets all three factors for addition to the TRI:

(1) It is undisputed that a great number of TRI-listed chemicals are reasonably anticipated to be present at facilities within the industry. The most common HAPs emitted are toluene, hexane, benzene, xylenes, ethylene glycol, methanol, ethylbenzene, and 2,2,4-trimethylpentane. Drilling and well development use and release toxic chemicals such as acrylamide, propargyl alcohol, mercury, lead, and arsenic. And the hydraulic fracturing process uses substances containing at least forty-five TRI-listed chemicals, of which the most prevalent are methanol, 2-butoxyethanol, and ethylene glycol.

(2) The industry routinely manufactures, processes, or otherwise uses these chemicals throughout its processes. As demonstrated by both industry-wide reports and site-specific data, the industry emits HAPs via well completions, leaks, flares, and processing; uses, mobilizes, and brings to the surface a host of toxic chemicals in well development; injects millions of gallons of liquids containing fracking chemicals into wells; and releases these chemicals into the groundwater, injection wells, surface waters, landfills, wastewater treatment plans, and the atmosphere. EPA investigations, government studies, and peer-reviewed scientific articles have provided strong supporting evidence linking such releases to the industry.

(3) Adding the industry to the TRI unquestionably will increase the information made available pursuant to the TRI or otherwise further its purposes. As it stands, there are no adequate federal disclosure requirements. While legislation has been proposed, it has stalled in

Congress. The Bureau of Land Management's proposed disclosure rules apply only to hydraulic fracturing and only where federal or Indian oil and gas rights are involved, have not been finalized, and may be altered or weakened before finalization. And state disclosure laws are either nonexistent or riddled with gaps: For one, these laws generally apply only to chemicals used in hydraulic fracturing, yet even in this context they are woefully inadequate. There is hydraulic fracturing occurring in at least twenty-nine states, but only fourteen states have established chemical disclosure requirements—most of which provide for trade secret exemptions, and none of which approaches the public accessibility of the TRI. Moreover, the industry lacks sufficient coverage under substantive federal environmental laws, given the multiple statutory exemptions and regulatory opportunities on which EPA has passed. There is simply no adequate, comprehensive framework to ensure that information as to toxic chemicals used in oil and gas extraction is made available to the public.

Oil and gas facilities manufacture, process or use chemicals in amounts larger—and sometimes far larger—than the thresholds that determine whether reporting is required. By EPA estimates, the industry emits roughly 127,000 tons of HAPs per year, which is more than any other TRI-reporting industry—except electric utilities—and equivalent to almost thirty percent of all 2010 TRI-reported air releases. EPA data shows that the average wellhead releases approximately 1.7 tons of HAPs on completion and continues to leak HAPs at a rate of 0.671 tons per year; and data on Texas emission events—i.e., emissions in addition to regular operations—shows that individual compressors and fractionators emit as much as 25.76 and 41.28 tons of HAPs per year, respectively. Because emissions represent only a fraction of the hazardous pollutants (like benzene and hexanes) that are components of the oil and gas that is extracted and processed, these facilities will clearly meet the threshold for reporting. For example, natural gas processing involves the common use of TRI-listed glycols and amines and the corresponding production and release of byproducts such as benzene, toluene, ethylbenzene, xylenes (collectively “BTEX compounds”), and hydrogen sulfide. And similarly, well development—and specifically hydraulic fracturing—uses upward of 2 to 4 millions of gallons of water and fluids containing at least forty-five TRI-listed chemicals. Even if the chemicals are a small percentage of these fluids, the sheer volume means that hundreds of thousands of pounds of chemicals are used per facility.

To best adhere to EPCRA and serve its purposes, EPA should ensure that the industry's many subcomponents, which collectively release large amounts of TRI-listed chemicals, report properly. Thus, EPA can and should properly apply the “facility” definition for reporting purposes as encompassing *multiple wells* and associated components—such as pits, storage tanks, and processing units—that are integrated into a common system and operated by a single company. Such an application is particularly fitting in light of EPCRA judicial interpretation cited herein, EPA's recent crafting of such a facility definition for the industry's greenhouse gas reporting under Subpart W, and the current industry's common practice of locating upward of one hundred wells in a small geographic area and operating them collectively. With such a definition, many wells and other operations would report under the TRI, significantly enhancing public information. But even if the facility definition were limited to individual units—e.g., wells, processing plants, storage tanks—the available data cited herein clearly shows that a significant amount of these units would still surpass TRI thresholds.

Finally, adding the industry will contribute to the primary goals of this important program, by giving the communities most affected—many of which are either encountering oil and gas extraction for the first time or confronting far more intensive activity than they have previously seen—the information they need to make decisions for their safety, health, and future. Furthermore, without disclosure requirements, oil and gas companies have no incentives to find their own way of preventing pollution or to choose less toxic alternatives. Adding the industry to the TRI will do much to provide these incentives. The lack of reliable or consistent information about the use and release of toxic chemicals by this industry make the public reporting required by TRI even more critical.

EPA clearly has the authority and responsibility to add the industry to coverage under the TRI. In fact, in late 2011, EPA took preliminary steps to exercise this authority once again and add new industry sectors for the first time since the 1997 additions. Among the suggested additions are industries that, like the oil and gas extraction industry, were considered but ultimately deferred in 1996 and 1997. In this way, EPA is well aware of its authority and continuing responsibility to update and expand the TRI industry sector to keep up with changing industries, public awareness, and information gaps. And EPA is now in a unique and convenient position to include the oil and gas extraction industry in its planned sector additions.

Accordingly, in light of the oil and gas extraction industry's long-running use and release of toxic chemicals, the increase of such with the advent of hydraulic fracturing, and the large amount of uncertainty that exists with respect to the amount and the impact of chemical releases from oil and gas operations, the need for greater public information has become much more pressing. Since the last occasion on which EPA considered its addition to the TRI, the industry has grown vastly, but regulation, disclosure, and public information have not kept pace. Consequently, the oil and gas extraction industry warrants listing now more than ever, and EPA must take action and finally add the industry to coverage under the TRI.

I. The Toxics Release Inventory and the "Right to Know"

Since its enactment, the TRI has served as a vital informational tool on toxic chemicals being released to the air, land, and water. While the TRI lacks the substantive pollution controls of other environmental laws and provisions, the reporting required by the TRI serves two critical goals: it encourages informed community-based environmental decision making and provides an incentive for industrial sectors to reduce or prevent pollution. As President Clinton recognized in 1995 and made a priority, it is therefore crucial that the TRI apply broadly across all industrial facilities with significant releases of toxic chemicals.³ Even with just the application of TRI's basic requirements, public knowledge will increase and releases of toxic chemicals will decrease.

As interpreted by EPA, the purposes of the TRI program are: "(1) Providing a complete profile of toxic chemical releases and other waste management activities; (2) compiling a broad-based national database for determining the success of environmental regulations; and (3)

³ Expediting Community Right-to-Know Initiatives, Memorandum for the Administrator of the Environmental Protection Agency and the Heads of Executive Departments and Agencies, 60 Fed. Reg. 41,791 (Aug. 8, 1995).

ensuring that the public has easy access to these data on releases of toxic chemicals to the environment.”⁴ In furtherance of these purposes, the TRI requires certain industrial sectors to file annual reports of the amounts of toxic chemicals released to the environment or disposed of in impoundments and landfills. These disclosures are published in the Inventory, are available online, and provide basic information about the environmental “footprint” of facilities.

Specifically, the TRI annual reporting requirements apply to owners and operators of facilities that: (a) have ten or more full-time employees, (b) are in a TRI-listed industrial sector, and (c) have manufactured, processed, or otherwise used one of the 682 TRI-listed toxic chemicals or categories in excess of the listed threshold quantity (generally 25,000 pounds for manufactured or processed chemicals, 10,000 pounds for “otherwise used” chemicals, and anywhere between 0.1 grams and 100 pounds for certain persistent bioaccumulative toxic chemicals) during the calendar year.⁵ For each such chemical above the threshold during the calendar year, the owner or operator must complete a toxic chemical release form and include the following information:

- (i) Whether the toxic chemical at the facility is manufactured, processed, or otherwise used, and the general category or categories of use of the chemical.
- (ii) An estimate of the maximum amounts (in ranges) of the toxic chemical present at the facility at any time during the preceding calendar year.
- (iii) For each wastestream, the waste treatment or disposal methods employed, and an estimate of the treatment efficiency typically achieved by such methods for that wastestream.
- (iv) The annual quantity of the toxic chemical entering each environmental medium.⁶

These environmental media include: onsite disposal in underground injection wells and landfills; onsite releases to air, land, and surface waters; offsite disposal in injection wells and landfills; and offsite disposal or releases in wastewater treatment plants, wells, landfills, and storage.⁷ The data submitted by facilities is public, available online, and searchable by facility name, location, industry sector, or chemical name.⁸

⁴ Addition of Facilities in Certain Industry Sectors; Revised Interpretation of Otherwise Use; Toxic Chemical Release Reporting; Community Right-to- Know, 62 Fed. Reg. 23,834, 23,836 (May 1, 1997); *see also* 61 Fed. Reg. at 33,592-93.

⁵ 40 U.S.C. § 11023(a), (b)(1)(A), (b), (f)(1); EPA, TRI PBT Chemical List, http://www.epa.gov/tri/trichemicals/pbt%20chemicals/pbt_chem_list.htm.

⁶ 40 U.S.C. § 11023(a), (g)(1)(C)

⁷ EPA, *TRI 2010 National Analysis* B-1 (2011) [hereafter *TRI 2010 National Analysis*], available at <http://www.epa.gov/tri/tridata/tri10/nationalanalysis/index.htm>.

⁸ *See* EPA, 2011 TRI Preliminary Dataset, <http://www.epa.gov/tri/tridata/preliminarydataset/index.html>; EPA, TRI Search, <http://www.epa.gov/enviro/facts/tri/search.html>.

While Congress' original establishment of the TRI only included facilities in SIC Codes 20 through 39—i.e., the manufacturing sectors—it also provided EPA with the ability to subject a new industry group to TRI reporting requirements if “such action is warranted on the basis of toxicity of the toxic chemical, proximity to other facilities that release toxic chemicals or to population centers, the history of releases of such chemical at such facility, or other such factors as . . . appropriate.”⁹ EPA retains this authority and may add the oil and gas extraction industry at any time it finds that such addition is warranted.

II. Background: the Composition of the Oil and Natural Gas Extraction Industry

The oil and gas extraction industry can be divided into three major processes or segments: (1) exploration and well development, (2) production and processing, and (3) site abandonment.¹⁰ Essentially, the extraction industry is a subset of the overall oil and gas industry that extends from exploration for well sites all the way up until the point that the oil and/or gas are transported to market by pipeline or otherwise.¹¹ As noted above, the oil and gas extraction industry was classified under SIC Code 13 in the 1996 rulemaking, but it has since then been identified under several NAICS codes.¹² These are primarily NAICS codes 211111 (Crude Petroleum and Natural Gas Extraction) and 211112 (Natural Gas Liquid Extraction), but also 213111 (Drilling Oil and Gas Wells), 213112 (Support Activities for Oil and Gas Operations), 213112 (Support Activities for Oil and Gas Operations), 238910 (Site Preparation Contractors), and 541360 (Geophysical Surveying and Mapping Services).¹³

In addition to this cutoff point of transport-to-market (and any point beyond, such as natural gas distribution lines to residences), three industrial processes are expressly not included in the oil and gas extraction industry: (1) refining crude petroleum into refined petroleum and hydrocarbons (NAICS 324110, Petroleum Refineries), (2) manufacturing or recovering hydrocarbons from petroleum (NAICS 325110, Petrochemical Manufacturing), such as ethylene “cracking,” and (3) recovering helium from natural gas (NAICS 325120, Industrial Gas Manufacturing).¹⁴ While other federal regulation of the industry sometimes chooses to include

⁹ 42 U.S.C. § 11023(b)(1)(B); *see also* 62 Fed. Reg. at 23,834 (“Congress recognized that the TRI program would need to evolve to meet the information needs of a better informed public and to fill information gaps that would become more apparent over time.”).

¹⁰ *Industry Sector Profile* at 15; *RIA* at 2-1.

¹¹ *See* NAICS Ass’n, 21112 Natural Gas Liquid Extraction, <http://www.naics.com/censusfiles/ND211112.HTM>; NAICS Ass’n, 211111 Crude Petroleum and Natural Gas Extraction, <http://www.naics.com/censusfiles/ND211111.HTM>; *see also* Clarification of the Regulatory Determination for Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas, and Geothermal Energy, 58 Fed. Reg. 15,284 (March 22, 1993).

¹² *See* 61 Fed. Reg. at 33,592; *Industry Sector Profile* at 4; *RIA* at 2-1.

¹³ *See* NAICS Ass’n, Free NAICS Look Up (cross-referencing SIC Code 13), <http://www.naics.com/search.htm>.

¹⁴ NAICS Ass’n, 21112 Natural Gas Liquid Extraction, <http://www.naics.com/censusfiles/ND211112.HTM>; NAICS Ass’n, 211111 Crude Petroleum

natural gas transportation segments—i.e., transmission and distribution—in its coverage of the extraction industry, such transportation is not generally included in the extraction industry, and this petition does not include natural gas transmission or distribution.¹⁵

A. Exploration and Well Development

The first major segment of the oil and gas extraction industry—exploration and well development—begins with exploration for formations associated with oil or natural gas deposits, and involves geophysical prospecting and exploratory drilling.¹⁶ Once this exploration has located an economically recoverable field, well development begins with the drilling of one or more wells.¹⁷ Well drilling involves the use of a rotary drill bit to chip off pieces of rock and form the well hole—or “wellbore.”¹⁸ As the drill bit forms a deeper wellbore, drilling fluid is pumped down the pipe connected to the drill bit, serving several important purposes: (1) cooling and lubricating the drill bit, (2) removing the drill cuttings and bringing them back to the surface, (3) preventing the collapse of the well bore, and (4) counterbalancing the high-pressure fluids in the oil and gas formation in order to prevent their entry into the well prematurely.¹⁹ As noted below, there are various types of drilling fluids, depending on the intended purpose and the stage of drilling, and many of the fluids’ constituents are TRI-listed chemicals.²⁰ At this stage, steel casing is inserted along the wellbore, both to prevent groundwater from entering the well and to prevent drilling fluids, oil, and gas from contaminating surrounding groundwater aquifers.²¹ Eventually, the casing is cemented, and this permanent casing is responsible for preventing groundwater contamination over the life of the well.²² As discussed herein, casing failures have been the cause of toxic constituent releases to groundwater.²³

These processes were the extent of drilling until recently, but the past decade has seen the popularization of the additional process of horizontal hydraulic fracturing. While horizontal drilling has existed since the 1950s and hydraulic fracturing was first innovated in the 1940s, modern technologies have allowed the combination of the processes in order to extract much larger amounts of oil and natural gas from a well.²⁴ Specifically, once the wellbore reaches the intended depth, the drill bit is steered in order to drill horizontally—typically 1,000 to 6,000 feet,

and Natural Gas Extraction, <http://www.naics.com/censusfiles/ND211111.HTM>; *Industry Sector Profile* at 3; Maarten Neelis et al., Berkeley Nat’l Laboratory, *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry* 3 (2008), available at http://www.energystar.gov/ia/business/industry/Petrochemical_Industry.pdf.

¹⁵ See RIA at 2-1; *Industry Sector Profile* at 3.

¹⁶ See RIA at 2-4; *Industry Sector Profile* at 15.

¹⁷ RIA at 2-4; *Industry Sector Profile* at 17.

¹⁸ *Industry Sector Profile* at 17.

¹⁹ *Id.* at 17-18; RIA at 2-4.

²⁰ See Part III.D.1, 2, *infra*.

²¹ RIA at 2-4; *Industry Sector Profile* at 21.

²² *Id.*

²³ See Part III.D.2.a.iii, *infra*.

²⁴ RIA at 2-4-2-5.

but as far as 10,000 feet from the well.²⁵ At that point, fluids are pumped into the well under high pressure—sometimes preceded by a charge to form initial fractures—in order to hydraulically fracture (or “frack”) the surrounding formation for greater release of the oil and gas contained therein.²⁶ Like drilling fluids, these fracking fluids also contain a variety of constituents, including TRI-listed chemicals, though many such fluids are proprietary blends for which companies claim protection as trade secrets.²⁷ Finally, mixtures known as “proppants”—typically sand, but also other materials—are also injected in order to “prop” the fractures open.²⁸

The final process of well development is well completion, which is particularly notable in hydraulically fractured wells due to the large emissions of natural gas, along with its toxic components, that accompany completion.²⁹ Once a hydraulically fractured—or refractured—well successfully releases natural gas from the fractured formation, the pressure of the natural gas pushes the injected frack fluids and proppant out of the well at high velocity, typically into a nearby surface impoundment.³⁰ Unless this “flowback” is controlled via a “reduced emission completion,” an estimated average 23 tons of volatile organic compounds (“VOCs”) are vented directly to the atmosphere.³¹ By contrast, conventional gas wells are estimated to vent roughly 0.1 tons of VOCs.³² Using EPA’s emission-estimating ratios, approximately 1.7 tons of HAPs are released in the average hydraulically fractured well completion.³³

²⁵ See OMB Watch, *The Right to Know, The Responsibility to Protect: State Actions Are Inadequate to Ensure Effective Disclosure of the Chemicals Used in Natural Gas Fracking* 11 (July 2012) [hereafter *OMB Watch Report*], available at <http://www.ombwatch.org/naturalgasfrackingdisclosure>.

²⁶ *RIA* at 2-5.

²⁷ See Minority Staff, Committee on Energy and Commerce, U.S. House of Representatives, *Chemicals Used in Hydraulic Fracturing* 2 (April 2011) [hereafter *House Committee Report*], available at <http://democrats.energycommerce.house.gov/sites/default/files/documents/Hydraulic%20Fracturing%20Report%204.18.11.pdf>.

²⁸ *RIA* at 2-5, 3-5.

²⁹ *Id.* at 3-5.

³⁰ *Id.* at 3-5-3-6.

³¹ *Id.* at 3-6.

³² *Id.*

³³ To reach this figure of 1.7 tons of HAPs per well completion, Petitioners applied EPA’s *Gas Composition Memo* ratio of 0.0726 HAP:VOC for completions of hydraulically fractured natural gas wells to the *RIA* “estimate that uncontrolled natural gas well completion emissions for a hydraulically fractured natural gas well are about 23 tons of VOC.” See *id.* at 3-6; Memorandum from Heather P. Brown, P.E., EC/R Incorporated, to Bruce Moore, EPA, *Re: Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking* 12 Tbl. 9 (July 28, 2011) [hereafter *Gas Composition Memo*]; see also note 137, *infra*, and surrounding text (calculating final air rule’s HAP reductions per well completion as 1.562 tons per year).

B. Production and Processing

Production and processing begin after successful well development and involves bringing the oil and gas to the surface, separating the liquid and gas components, and removing the impurities from natural gas.³⁴ The process differs depending on whether the well is conventional or unconventional (e.g., a hydraulically fractured well), but the end goal in either case is to produce crude oil for storage or transport to a refinery and/or to produce natural gas of high enough quality to pass through transportation systems.³⁵

In conventional oil and gas production, oil is typically found in an underground reservoir of oil, frequently with a natural gas “cap.”³⁶ “Primary production” of the resources is typically driven by the pressure of the reservoir itself and extracts roughly thirty to thirty-five percent of the oil.³⁷ “Secondary recovery” occurs once the natural pressure of the reservoir has abated and involves the injection of produced water or gas to re-pressurize the reservoir and continue recovery.³⁸ The final method of recovery from reservoirs is “tertiary recovery,” which removes the last amounts of extractable oil and gas, and involves the injection of chemicals, gas, or steam into the well.³⁹

Unlike conventional sources, unconventional sources of oil and gas do not involve reservoirs and accordingly do not use the same methods of production.⁴⁰ Instead, as noted above, extraction is more a function of additional processes in the well drilling—most notably in recent years, the addition of horizontal drilling and hydraulic fracturing to release oil and gas trapped in rock formations.⁴¹

Once natural gas has been extracted from a well, it must be processed to the point of becoming “pipeline-quality” gas—that is, gas of high enough quality to allow its transport by pipeline to consumers.⁴² Essentially, natural gas processing (also known as “conditioning”) is the process by which impurities are removed from the gas stream, specifically including water vapor, hydrogen sulfide, carbon dioxide, high-vapor-pressure hydrocarbons such as the BTEX compounds, and other gases such as nitrogen.⁴³ Two of the most common methods involved in natural gas processing are “dehydration,” in which the gas is exposed to a glycol to remove water vapor, and “sweetening,” in which the gas is exposed to an amine solution and heated to remove hydrogen sulfide.⁴⁴ Natural gas processing manufactures, processes, and otherwise uses a

³⁴ *Industry Sector Profile* at 28.

³⁵ *Id.* at 31.

³⁶ *RIA* at 2-5.

³⁷ *Id.* at 2-6; *Industry Sector Profile* at 28.

³⁸ *RIA* at 2-6; *Industry Sector Profile* at 29.

³⁹ *RIA* at 2-6; *Industry Sector Profile* at 30.

⁴⁰ *RIA* at 2-6.

⁴¹ *Id.*

⁴² *Id.* at 2-7; *Industry Sector Profile* at 31.

⁴³ *Industry Sector Profile* at 31; *RIA* at 2-7-2-8.

⁴⁴ *Industry Sector Profile* at 31-32; *RIA* at 2-7-2-8.

variety of TRI-listed chemicals and is accordingly responsible for a significant amount of HAP emissions.⁴⁵

The primary units involved in natural gas processing are processing plants, glycol dehydrators, compressors, gathering lines, and storage vessels.⁴⁶ All of these units result in large emissions of HAPs, including BTEX compounds and hydrogen sulfide, either as a result of their processes or via flaring, venting, or fugitive emissions.⁴⁷ Depending on the operator, the site, and the composition of the gas, processing by these components can occur in the field and/or at a large natural gas processing plant, and each natural gas extraction operation is accordingly different.⁴⁸

Prior to arrival at a processing plant—or, in many cases, as an alternative to a standalone processing plant—natural gas from the wellhead is processed in the field at “skid-mount plants” or compressor stations.⁴⁹ These field units can dehydrate the gas, remove contaminants (such as hydrogen sulfide from “sour” gas), and extract nitrogen.⁵⁰ Gas is transported to these units via the “gathering” process, which involves stations and small-diameter pipes that gather gas from one or many—in some cases, up to a hundred or more—wells. Because of the number of wells involved and the potential distance to be traveled, gathering often requires the use of compressors to insure adequate line pressure.⁵¹ In fact, HAP emissions from such gathering compressors were a major consideration in the recent air rule, as discussed below.

Glycol dehydration units may be located in the field, among various units at condensate tank batteries, or at a processing plant and serve the single purpose of removing water and other condensates from natural gas.⁵² This dehydration is necessary to allow the gas to travel freely in transmission pipelines and distribution lines.⁵³ Glycol dehydrators may serve one or several wells—as is the case in centralized operations such as Dimock, as discussed below—and their size accordingly varies.

It is not clear how many glycol dehydrators are currently operating in the natural gas extraction industry. EPA’s recently finalized air rule will apply to at least ninety-two “large” glycol dehydrators—i.e., units with benzene emissions greater than 1 ton per year—in the

⁴⁵ See *RIA* at 3-7-3-8; Part III.B.2, *infra*.

⁴⁶ EIA, *Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market* 2-3 (2006) [hereafter *Natural Gas Processing*]; *RIA* at 3-4-3-5.

⁴⁷ Earthworks, Sources of Oil and Gas Air Pollution, http://www.earthworksaction.org/issues/detail/sources_of_oil_and_gas_air_pollution.

⁴⁸ *Industry Sector Profile* at 31; *Natural Gas Processing* at 3.

⁴⁹ *Natural Gas Processing* at 3.

⁵⁰ *Id.* at 2 Fig. 1.

⁵¹ *Id.* at 3.

⁵² Memorandum from Heather P. Brown, P.E., to Bruce Moore and Greg Nizich, EPA, *Re: Technology Review for the Final Amendments to Standards for the Oil and Natural Gas Production and Natural Gas Transmission and Storage Source Categories* 4 (April 17, 2012) [hereafter *Technology Review Memo*].

⁵³ *Id.*; *Industry Sector Profile* at 31.

production source category and fifteen large dehydrators in the transmission and storage category, which may partially overlap with the extraction sector.⁵⁴ The rule also applies to “small” glycol dehydrators located at major sources—i.e., dehydrators emitting less than 1 ton per year of benzene—for a total of seventy-four small dehydrators in the production source category and seven in the transmission and storage source category.⁵⁵ There are undoubtedly many more dehydrators than this, given the air rule’s application to only a small percentage of overall industry emissions,⁵⁶ and given EPA’s 1993 estimate that there existed nearly 40,000 glycol dehydrators nationwide, of which roughly 31,500 were in the production and processing industry segments.⁵⁷ As their name suggests, glycol dehydrators use glycols for water absorption, including the TRI-listed ethylene glycol.⁵⁸ They also emit a significant amount of HAPs, and in particular BTEX compounds, from leaks and venting.⁵⁹

In cases where a well produces a gas stream containing hydrogen sulfide (“sour gas”) and/or carbon dioxide “acid gas”), sweetening is the procedure that removes these contaminants, either in the field, at a tank battery, or at a processing plant.⁶⁰ As noted above, the most common method of sweetening is by exposing the gas stream to an amine solution, which reacts with the contaminants and removes them from the gas. The solution of contaminants and reacted amine is then heated, which separates the contaminant gas byproducts and regenerates the amine. The hydrogen sulfide is typically disposed of by flaring, incinerating, or in some cases sending it to a facility to generate saleable elemental sulfur.⁶¹ Though the majority of onshore gas production is classified as “sweet,” EPA’s recent emission factors for well completions list the average hydrogen sulfide composition of natural gas as 2.027 percent by volume.⁶²

In addition to the compressors associated with the gathering process, compressors are also important components in natural gas processing, both within natural gas processing plants and as standalone components in the process, as noted above. EPA evaluated both centrifugal and reciprocating compressors in the recent air rule due to their regular emissions of VOCs and

⁵⁴ *Technology Review Memo* at 19 Tbl. 10.

⁵⁵ *RIA* at 3-35 Tbl. 3-9.

⁵⁶ For example, EPA estimated that the proposed air rule would reduce HAP emissions by 38,000 tons per year, representing an industry-wide “reduction of nearly 30 percent.” See EPA, *Proposed Amendments to Air Regulations for the Oil and Natural Gas Industry: Fact Sheet 1-2* (2011) [hereafter *Proposed Air Rule Fact Sheet*], available at <http://epa.gov/airquality/oilandgas/pdfs/20110728factsheet.pdf>. By contrast, the final air rule reduces HAP emissions by roughly 12,000 tons per year, or less than ten percent of the industry’s emissions. See EPA, *Overview of Final Amendments to Air Regulations for the Oil and Natural Gas Industry 2* (2012), available at <http://www.epa.gov/airquality/oilandgas/pdfs/20120417fs.pdf>.

⁵⁷ EPA, *Methane Emissions from the Natural Gas Industry, Volume 14: Glycol Dehydrators 2, A-3* (1996) (estimating that 95 percent of dehydrators are glycol dehydrators).

⁵⁸ *Natural Gas Processing* at 4.

⁵⁹ See *Technology Review Memo*, Attachment 2, Attachment 4; *RIA* at 3-35 Tbl. 3-9.

⁶⁰ *RIA* at 2-3, 2-8.

⁶¹ *Id.* at 2-8.

⁶² *Gas Composition Memo* at 11 Tbl. 8.

HAPs.⁶³ In particular, centrifugal compressors tend to emit pollutants from the seal around their rotating shafts. Where “wet” oil-based seals are used, these emissions occur when the oil seal is purged of absorbed gases, thereby venting the pollutants. Where “dry” mechanical seals are used, emissions are reduced, but still occur as fugitive emissions from the seals.⁶⁴ Reciprocating compressors tend to leak natural gas during normal operations, particularly via the piston rod packing systems, though this can be reduced through regular monitoring and replacement of parts.⁶⁵ As described below, the air rule estimated an average per-unit reduction of 0.7 tons per year of HAPs from centrifugal compressors and 0.20 tons per year of HAPs from reciprocating compressors at processing plants.⁶⁶

Inherent in natural gas processing as well as well development and oil and gas production is the use of storage vessels or larger combined “tank batteries” to “separate, treat, and store crude oil, condensate, natural gas, [] produced water,” and other byproducts from processing.⁶⁷ Such tanks are continuously receiving well products and byproducts, often from a number of nearby wells, and they accordingly emit VOCs and HAPs “as a result of working, breathing, and flash losses.”⁶⁸ These emissions are significant: the air rule’s estimated reductions alone number in several tons per year of HAPs per individual storage tank.⁶⁹

Finally, processing plants are the largest of the processing components and, accordingly as noted below, are the largest individual emitters of HAPs in the industry.⁷⁰ Depending on the plant, processing plants may handle every process after the removal of condensate: from dehydration through to fractionation.⁷¹ Based on 2010 numbers, there are approximately 493 natural gas processing plants currently operating in the United States with a combined operating capacity of 77 billion cubic feet of natural gas per day.⁷² While the plants’ collective operating capacity has been steadily increasing, the number of plants has concurrently decreased.⁷³ Large processing plants are overwhelmingly situated in Gulf and Western states.⁷⁴

⁶³ *RIA* at 3-3.

⁶⁴ *Id.*

⁶⁵ *Id.*

⁶⁶ *RIA* at 3-12 Tbl. 3-2, 3-20 Tbl. 3-4.

⁶⁷ *Id.* at 3-5.

⁶⁸ *Id.*; Earthworks, Sources of Oil and Gas Air Pollution,

http://www.earthworksaction.org/issues/detail/sources_of_oil_and_gas_air_pollution.

⁶⁹ See *RIA* at 3-12 Tbl. 3-2, 3-20 Tbl. 3-4.

⁷⁰ See, e.g., See EIP, *Accident Prone: Malfunctions and “Abnormal” Emission Events at Refineries, Chemical Plants, and Natural Gas Facilities in Texas, 2009-2011* App. A (2012) [hereafter *Accident Prone*], available at

http://www.environmentalintegrity.org/news_reports/07_18_2012.php.

⁷¹ *Natural Gas Processing* at 2 Fig. 1.

⁷² EIA, *Natural Gas Processing Plants in the United States: 2010 Update* (2011), http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngpps2009/.

⁷³ *Id.*

⁷⁴ *Id.*; *Natural Gas Processing* at 6-7; EIA, *Natural Gas Processing Plants in the United States: 2010 Update* (2011), http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngpps2009/overview.cfm.

After natural gas processing is complete, the gas begins transportation by pipeline to market, thereby commencing the natural gas transmission and distribution sector, and/or is stored in large storage tanks.

C. Site Abandonment

Once a well is no longer economically viable—whether this occurs during development or after a long period of production—site abandonment begins.⁷⁵ The basic components of site abandonment are plugging the well to prevent migration of fluids and restoration of the surface.⁷⁶ Though hydraulically fractured wells are deeper than conventional wells and include horizontal segments, traditional well plugging consists of at least three cement plugs, each 100 to 200 feet long, and located at the production zone of the wellbore, in the middle of the wellbore, and within a few hundred feet of the surface.⁷⁷ Fluid is placed between the plugs in order to maintain pressure.⁷⁸ Thereafter, the well casing is cut off and capped below the surface and surface reclamation takes place.⁷⁹ If all goes according to plan, the abandonment is meant to ensure that fluids will no longer migrate within the well or into the surrounding groundwater.

An alternative to plugging the well—particularly if other producing wells are nearby—is to use it for the disposal of other wells’ produced water and fluids.⁸⁰ Unlike the injection of fluids in the process of hydraulic fracturing, which is exempt from Underground Injection Control coverage under the Safe Drinking Water Act, as noted below, injection wells for the disposal of liquid wastes—e.g., flowback water and the chemical constituents it contains—are covered by the Act as Class II wells.⁸¹

D. EPA’s Consideration of Adding the Oil and Gas Extraction Industry to the TRI, and the Industry Developments Since this Consideration

In 1996 and 1997, EPA initiated rulemaking under its EPRCA section 313(b)(1)(B) authority to add several additional sectors to the TRI list of facilities: “metal mining, coal mining, electric utilities, commercial hazardous waste treatment, chemicals and allied products-wholesale, petroleum bulk plants and terminals-wholesale, and solvent recovery services.”⁸² Given that this was EPA’s first use of its sector-addition authority—undertaken pursuant to a

⁷⁵ *Industry Sector Profile* at 15, 33.

⁷⁶ *Id.*

⁷⁷ *Id.* at 33.

⁷⁸ *Id.*

⁷⁹ *Id.*

⁸⁰ *Id.*

⁸¹ *Id.*; see EPA, Class II Wells - Oil and Gas Related Injection Wells (Class II), <http://water.epa.gov/type/groundwater/uic/class2/index.cfm>.

⁸² 62 Fed. Reg. at 23,834.

directive by President Clinton to expedite all sector additions⁸³—it articulated three primary factors against which it considered each of the industrial sectors:

(1) Whether one or more toxic chemicals are reasonably anticipated to be present at facilities within the candidate industry group (“chemical” factor); (2) whether facilities within the candidate industry group “manufacture,” “process,” or “otherwise use” these toxic chemicals (“activity” factor); and (3) whether facilities within the candidate industry group can reasonably be anticipated to increase the information made available pursuant to EPCRA section 313, or otherwise further the purposes of EPCRA section 313 (“information” factor).⁸⁴

While EPA ultimately opted not to add the oil and gas extraction industry, the sector was among twenty-five major industry groups that EPA initially considered in its development of the 1996 proposed rule and 1997 final rule. EPA considered these twenty-five groups—the “Tier I list”—to be those industries “for which reporting would be most beneficial to community right-to-know.”⁸⁵ Indeed, when EPA reduced this initial list based on factors such as the industries’ relationship to the manufacturing process, “greater importance in terms of their potential value to section 313 reporting,” and “an overlay of regulatory definitions and developments, existing program guidance, and any exemptions pertinent to activities identified for the primary candidates,” the oil and gas extraction industry remained as one of few sectors still considered.⁸⁶ Ultimately, though, while EPA “believed [the sector] to conduct significant management activities that involve EPCRA section 313 chemicals,” it chose to defer adding it to the TRI list on the basis of technical questions as to how the industry’s smallest units—individual wells—would fit with EPCRA’s definition of “facility.”⁸⁷

In other words, there was little question that the oil and gas extraction industry managed “significant quantities of EPCRA section 313 chemicals,” met EPA’s three factors, or was an overall good candidate for inclusion in keeping with the purpose of the TRI. Rather, EPA questioned whether the industry could escape reporting thresholds pursuant to the definition of what constituted a facility, and thereby chose to “address[] these issues in the future.”⁸⁸

Since this time, the modern oil and gas extraction industry has grown into something very different than the industry that EPA considered in 1996 and 1997, due largely to the advent of

⁸³ 60 Fed. Reg. at 41,791 (directing EPA’s “[c]ontinuation on an expedited basis of the public notice and comment rulemaking proceedings to consider whether, as appropriate and consistent with section 313(b) of EPCRA, 42 U.S.C. 11023(b), to add to the list of Standard Industrial Classification (‘SIC’) Code designations of 20 through 39 (as in effect on July 1, 1985).”).

⁸⁴ 62 Fed. Reg. at 23,836.

⁸⁵ 61 Fed. Reg. at 33,591.

⁸⁶ *Id.* at 33,591-92.

⁸⁷ *Id.* at 33,592.

⁸⁸ *Id.*; see also *Industry Sector Profile* at 114 (“The possible addition of the industry was considered carefully in 1996, but was not added at that time. The proposal may enter the proposed rule stage in December, 2000, but no definite schedule had been set at the time of the publication of this document.”).

the natural gas extraction technique of horizontal hydraulic fracturing and its accompanying changes in the oil and natural gas market. As a direct result of this technique, which has only become common in the last decade, the number of wells and facilities has vastly increased, along with their proximity to each other and residential properties, the variety of substances and chemicals used, employees involved, and the extent of persons and the environment affected by its releases. Specifically, the number of natural gas wells has increased by forty-two percent between 2000 and 2010, and natural gas production reached 24,170 billion cubic feet in 2011, the highest level achieved since the early 1970s.⁸⁹ And while EPA's industry sector profile reported 303,724 wells producing primarily natural gas in 1999, there are now almost 500,000 in operation in at least thirty states.⁹⁰ Furthermore, whereas EPA's proposed rule cited hydraulic fracturing as an aside, and solely with respect to the fracturing of coal beds, currently nine out of ten natural gas wells now use hydraulic fracturing and its associated processes.⁹¹

The horizontal hydraulic fracturing technique that has fostered this expanded production is also, by its nature, a technique utilizing more chemicals and imposing greater environmental and human health impacts. For one, the fracturing process requires huge amounts of water and fracturing fluids—estimated at 2 to 4 million gallons per individual well, though higher figures have also been recorded—which are used for a number of functions, such as increasing the fracturing of the underlying geologic formations, dissolving rock, preventing microbial growth, increasing or reducing viscosity, and preventing corrosion.⁹² As described below, these fluids contain a wide range of chemicals, many of which are toxic and many of which are kept confidential pursuant to claims of “trade secrets.”⁹³ Secondly, wells now extend not only 6,000 to 10,000 feet deep, but also include horizontally drilled sections, which typically extend 1,000 to 6,000 feet in either direction and may be as long as 10,000 feet.⁹⁴

As the oil and gas extraction industry sector's growth has rapidly occurred, the need for greater public information has become much more pressing. Since EPA's 1996 proposed rule, the industry has been legislatively exempted from several key federal environmental laws,⁹⁵ and the state and federal disclosure laws that have since arisen are insufficient and riddled with

⁸⁹ See EIA, *Natural Gas Monthly* 3 Tbl. 1 (Sep. 2011), available at <http://www.eia.gov/naturalgas/monthly/>; *OMB Watch Report* at 9; *House Committee Report* at 2.

⁹⁰ *Industry Sector Profile* at 9; U.S. Energy Information Administration, *Natural Gas Annual 2010* at 1, 4, 6 (Dec. 2011) [hereafter *Natural Gas Annual 2010*], available at <http://205.254.135.7/naturalgas/annual/pdf/nga10.pdf>; EIA, Number of Producing Natural Gas Wells, http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm.

⁹¹ *OMB Watch Report* at 2 (citing ProPublica, What Is Hydraulic Fracturing?, <http://www.propublica.org/special/hydraulic-fracturing-national>).

⁹² See *OMB Watch Report* at 11-12; *House Committee Report* at 2-3; Colorado Oil & Gas Ass'n, Colorado Water Supply and Hydraulic Fracturing (“To fracture an average horizontal well in Colorado, and most other parts of the nation, two to five million gallons of water are needed.”), http://www.coga.org/index.php/Colorado_Water_Supply_and_Hydraulic_Fracturing.

⁹³ See *House Committee Report* at 2, 11-12.

⁹⁴ See *OMB Watch Report* at 11.

⁹⁵ See Part IV.A.2, *infra*.

gaps.⁹⁶ Accordingly, in sharp contrast to the purposes of EPCRA, there exists no adequate incentive for the industry to change its behavior and reduce its release of toxic chemicals.⁹⁷

Coincidentally, EPA has recently commenced preliminary development for a new TRI industry-addition rule—the first such rule since the 1997 additions.⁹⁸ In late 2011, EPA opened a “discussion forum” in order to “help [] define the scope of a potential forthcoming rule” for the addition of six industry sectors to the TRI: “Iron Ore Mining, Phosphate Mining, Solid Waste Combustors and Incinerators, Large Dry Cleaning, Petroleum Bulk Storage, and Steam Generation from Coal and/or Oil.”⁹⁹ While the oil and gas extraction industry is not among the proposed sectors, all but one of these proposed industry sectors are either expansions of sectors added in 1997 or—like the oil and gas extraction industry—sectors originally deferred in 1996–97. For example, phosphate mining and iron ore mining were excluded in the 1996 proposed rule and the 1997 final rule, respectively, on the basis of EPA beliefs that the industries did not involve sufficient TRI-listed chemicals.¹⁰⁰ And the proposed additions of solid waste combustors and incinerators, bulk petroleum storage, and steam generation from coal and/or oil are all expansions of industries added in the 1997 final rule.¹⁰¹ That is to say, EPA has reconsidered these industries against their current states and data.

To that end, Petitioner OMB Watch commented on the scope of the addition rule. While OMB Watch strongly supported the addition of the six industries as a valuable strengthening of the TRI, it added that significant contributors such as the oil and gas extraction industry were not yet TRI-reporting sectors and that “EPA should take immediate steps to review and add such polluting industry sectors to TRI.”¹⁰² According to EPA, the discussion forum closed as of November 10, 2011, and “[a] proposed rule may be published by early 2013.”¹⁰³

⁹⁶ See *OMB Watch Report* at 54–55; see also Part IV.A.3, *infra*.

⁹⁷ See 62 Fed. Reg. at 23,885.

⁹⁸ See EPA, TRI Industry Sectors Expansion, <http://exchange.regulations.gov/topic/trisectorsrule/>.

⁹⁹ *Id.*

¹⁰⁰ See EPA, Phosphate Mining, <http://exchange.regulations.gov/topic/trisectorsrule/phosphate-mining> (citing 63 Fed. Reg. at 33,592); EPA, Iron Ore Mining, <http://exchange.regulations.gov/topic/trisectorsrule/iron-ore-mining> (citing 62 Fed. Reg. at 23,859).

¹⁰¹ See EPA, Solid Waste Combustors and Incinerators, <http://exchange.regulations.gov/topic/trisectorsrule/solid-waste-combustors>; EPA, Bulk Petroleum Storage, <http://exchange.regulations.gov/topic/trisectorsrule/bulk-petroleum-storage>; EPA, Steam Generating Facilities, <http://exchange.regulations.gov/topic/trisectorsrule/steam-generating-facilities>.

¹⁰² See EPA, TRI Industry Sector Scope Discussion, <http://exchange.regulations.gov/topic/trisectorsrule/discussion/tri-industry-sector-scope> (quoting comments by OMB Watch).

¹⁰³ EPA, TRI on Exchange, <http://exchange.regulations.gov/topic/trisectorsrule/agencyintro/tri-exchange>.

In short, if the oil and gas extraction sector met EPA's factors and qualified as a good candidate for addition to the TRI in 1996, there is no question that it does now. And, even if sector had not previously met the factors for inclusion, adding the sector to the TRI now satisfies each of these factors and will serve to achieve the purposes of EPCRA. With a proposed expansion of the industry sector scope set for 2013 and comments already encouraging this needed addition, EPA is uniquely well-positioned to review and add the oil and gas extraction sector to the TRI.

III. The Oil and Gas Extraction Sector Clearly Meets the Chemical and Activity Factors

Under the "chemical" factor, EPA examines whether one or more listed toxic chemicals are reasonably anticipated to be present at facilities within the industry group.¹⁰⁴ In addressing this factor, "EPA will consider evidence indicating that facilities within an industry group are reasonably anticipated to have involvement with one or more EPCRA section 313 listed toxic chemicals as part of its routine operations."¹⁰⁵ Under the "activity" factor, EPA considers whether facilities within the candidate industry group manufacture, process, or otherwise use one or more TRI chemicals.¹⁰⁶ Because these two factors are so closely related—and, in fact, overlap to a large extent—it makes sense to collapse the queries into one and consider them together, examining each major category of chemicals used by the industry and discussing the chemicals involved and used for each, along with some description of the environmental footprint and media of release.

There appear to be three primary categories of TRI-listed chemicals manufactured, processed, or used by the industry: (1) chemicals contained within natural gas, (2) chemicals used in or resulting from processing, and (3) chemicals used in or resulting from well development activities. Although there is significant overlap of chemicals across all three categories—e.g., BTEX compounds—for each category, the chemicals will be listed, followed by the environmental media of release and any documented accounts.

As a general matter, the oil and gas extraction industry has involvement with and uses a large variety of chemicals listed under the TRI. As EPA noted in its 1996 proposed rule, the oil and gas extraction sector "conduct[s] significant management activities that involve EPCRA section 313 chemicals."¹⁰⁷ Moreover, in EPA's 2000 profile of the Oil and Gas Extraction Industry, it noted the wide range of toxic chemicals used and released by the sector.¹⁰⁸ As discussed in greater detail herein along with their uses, such toxic chemicals include: organics such as the BTEX compounds, naphthalene, phenanthrene, bromodichloromethane, and pentachlorophenol; inorganics such as lead, arsenic, barium, antimony, sulfur, zinc, nickel, manganese, and silver; and radionuclides such as uranium, radon, and radium.¹⁰⁹

¹⁰⁴ 61 Fed. Reg. at 33,594.

¹⁰⁵ *Id.*

¹⁰⁶ 62 Fed. Reg. at 23,836.

¹⁰⁷ *Id.* at 33,592.

¹⁰⁸ *Industry Sector Profile.*

¹⁰⁹ *Id.* at 39, 54-55, 58, 60.

A. The Oil and Gas Extraction Sector Manufactures, Processes, and Otherwise Uses TRI-Listed Chemicals

As an industry that extracts a substance that contains a mixture of TRI-listed chemicals, processes this substance to remove impurities and make it suitable for transport to the market, and otherwise uses this substance and a variety of other TRI-listed chemicals over the course of the process, it is clear that the oil and gas extraction industry easily meets EPCRA's and EPA's definitions for manufacturing, processing, or otherwise using TRI-listed chemicals.

EPCRA defines "manufacture" to mean "to produce, prepare, import, or compound a toxic chemical."¹¹⁰ EPA's longstanding regulations echo this statutory definition and add that:

Manufacture also applies to a toxic chemical that is produced coincidentally during the manufacture, processing, use, or disposal of another chemical or mixture of chemicals, including a toxic chemical that is separated from that other chemical or mixture of chemicals as a byproduct, and a toxic chemical that remains in that other chemical or mixture of chemicals as an impurity.¹¹¹

Most recently, EPA's TRI instructions provide the following as examples of "coincidental manufacture": the treatment of wastewater to remove nitric acid, thereby resulting in the coincidental manufacture of a nitrate compound, and the creation of metal compounds, acids, and hydrogen fluoride via the combustion of coal.¹¹²

EPCRA defines the term "process" to mean:

the preparation of a toxic chemical, after its manufacture, for distribution in commerce--

(I) in the same form or physical state as, or in a different form or physical state from, that in which it was received by the person so preparing such chemical, or

(II) as part of an article containing the toxic chemical.¹¹³

EPA's TRI instructions note that processing is "usually the incorporation of an EPCRA Section 313 chemical into a product," but that "a facility may process an impurity that already exists in a raw material by distributing that impurity in commerce," and that "[t]he term also applies to the

¹¹⁰ 42 U.S.C. § 11023(b)(1)(C)(i)

¹¹¹ 40 C.F.R. § 372.3.

¹¹² EPA, *Toxic Release Inventory Reporting Forms and Instructions* 14, 15 (Reporting Year 2011) [hereafter *TRI Instructions*], available at http://www.epa.gov/tri/report/rfi/ry2011rfi_v3.pdf.

¹¹³ 42 U.S.C. § 11023(b)(1)(C)(ii).

processing of a mixture . . . that contains a listed EPCRA Section 313 chemical as one component.”¹¹⁴

Finally, while the term “otherwise use” is not defined in the statute, it is likely the most expansive, as “EPA has interpreted the term by regulation to encompass any activity involving a listed toxic chemical at a facility that does not fall under the definitions of ‘manufacture’ or ‘process.’”¹¹⁵ In its TRI instructions, EPA echoes this definition, with the only limitations being with respect to certain disposal or destruction activities.¹¹⁶ In the context of the mining industry, EPA has determined that “EPCRA section 313 toxic chemicals are ‘otherwise used’ during the extraction or beneficiation activities at many of the covered mining facilities.”¹¹⁷ Another example EPA has provided is the use of toluene to separate two components of a mixture by dissolving one in the toluene.¹¹⁸

Through one process or another, the oil and gas extraction industry conducts all three of these uses. The most obviously applicable category would appear to be “otherwise use,” given its expansiveness and the unique ways in which the industry “uses” natural gas and its constituents—although “manufacture” and “process” could certainly apply to specific segments of the industry. For example, sweetening of natural gas results in the manufacture of hydrogen sulfide as a byproduct. Whether the byproduct is later flared, vented, or otherwise released, it must be counted due to this “coincidental manufacture” necessary to the processing of sour gas. The same could be said of the byproducts of glycol dehydration—although the glycol itself would more properly fall under the category of “otherwise used,” like the toluene example above. Similarly, although EPA does refer to “process” as “usually” being the incorporation of a chemical into a product, it is also apparent that the application of “process” under EPCRA could apply to the oil and gas extraction industry’s numerous activities in preparation for transport to market.¹¹⁹

Overall, it is entirely clear that wherever “manufacture” or “process” would not apply, the oil and gas extraction industry unquestionably “otherwise uses” an extensive amount of toxic chemicals in the natural gas itself, in the products it uses to conduct its extraction and production—including drilling fluids, surfactants, and fracking fluids—and in the chemicals involved in processing.

¹¹⁴ TRI Instructions at 14.

¹¹⁵ 62 Fed. Reg. at 22,856; *see also* 40 C.F.R. § 372.3 (“Otherwise use of a toxic chemical does not include disposal, stabilization (without subsequent distribution in commerce), or treatment for destruction unless” the chemical was “received from off-site for the purposes of further waste management” or “manufactured as a result of waste management activities on materials received from off-site for the purposes of further waste management activities”).

¹¹⁶ TRI Instructions at 14.

¹¹⁷ 62 Fed. Reg. at 23,857.

¹¹⁸ TRI Instructions at 16.

¹¹⁹ *Id.* at 14.

B. Toxic Constituents of Natural Gas Released in Well Completions, Production, and Processing

The first category of TRI-listed chemicals used by the industry are those contained in natural gas and, as a result, used by the industry and released in significant numbers during well completions, leaks, processing, storage, and related activities.¹²⁰

I. TRI-Listed Chemicals Involved

EPA specifically examined the toxic constituents within natural gas as part of its recently finalized promulgation of standards under the Clean Air Act's New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") for the oil and gas industry ("final air rule").¹²¹ As part of this rulemaking, EPA generated an "average gas composition" that it could use in estimating emissions and the reductions thereof to be achieved by the rule. EPA drew from a number of sources across the natural gas industry and provided the proportions of gas—and specifically the HAPs and VOCs—produced and released by industrial processes.¹²² On this basis, EPA determined three representative compositions for natural gas: "Production" (i.e., the composition of natural gas during production and processing), "Transmission" (i.e., the composition of transport- or market-quality natural gas during transmission), and well completions and recompletions.¹²³ For production, those components listed in the TRI were, in order of presence and with volume and weight percentages:

- n-Hexane: 0.09 percent volume, 0.39 percent weight;
- Benzene: 0.022 percent volume, 0.083 percent weight;
- Toluene: 0.016 percent volume, 0.074 percent weight;
- Ethylbenzene: 0.00090 percent volume, 0.0047 percent weight;
- Xylenes (m-, p-, and o-): 0.0041 percent volume, 0.021 percent weight.¹²⁴

For well completions and recompletions, EPA found the TRI-listed components to be, by volume:

- Hydrogen sulfide: 2.027 percent volume;
- n-Hexane: 0.155 percent volume;
- Benzene: 0.005 percent volume;

¹²⁰ *RIA* at 3-2-3-8.

¹²¹ See Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 40 CFR Part 63, RIN 2060-AP76 (April 17, 2012) [hereafter *Final Air Rule*], available at <http://www.epa.gov/airquality/oilandgas/pdfs/20120417finalrule.pdf>. As of the date of this petition, the rule has been finalized but not yet published in the Federal Register. EPA has estimated that the rule will be published in July 2012. *Id.* at 1.

¹²² *Gas Composition Memo* at 1.

¹²³ *Id.* at 1-2, 9.

¹²⁴ *Id.* at 8 Tbl. 5.

- Toluene: 0.003 percent volume;
- Cyclohexane: 0.001 percent volume;
- Xylenes: 0.001 percent volume;
- Ethylbenzene: 0.000 percent volume;
- Hexanes: 0.000 percent volume.¹²⁵

Additionally, for the purposes of determining the composition of natural gas constituents after flaring, the Ventura County Air Pollution Control District developed HAP emission factors in 2001 based on EPA data.¹²⁶ By the factors' estimation, toxic pollutants are released in the following proportions during flaring, in pounds per million cubic feet of natural gas:

- Benzene: 0.159
- Formaldehyde: 1.169
- Polyaromatic hydrocarbons (including naphthalene): 0.014
- Naphthalene: 0.011
- Acetaldehyde: 0.043
- Acrolein: 0.010
- Propylene: 2.440
- Toluene: 0.058
- Xylenes: 0.029
- Ethylbenzene: 1.444
- Hexane: 0.029.¹²⁷

2. The Industry's Releases of the Natural Gas Toxic Constituents across Environmental Media

The industry's releases of the toxic constituents of natural gas are significant and, for obvious reasons, are primarily via air emissions. Though the above-listed constituents are seemingly present in limited concentrations, these amounts are significant when considered against sheer volume of natural gas being produced. That is, natural gas production reached 24,170 billion cubic feet in 2011; projections for 2012 production are even higher; nearly half a million natural gas wells are in operation; and 25,000 new and modified hydraulically fractured gas wells are completed each year.¹²⁸ Indeed, the current industry has been estimated to emit on

¹²⁵ *Id.* at 11 Tbl. 8.

¹²⁶ Ventura County Air Pollution Control District, *AB 2588 Combustion Emission Factors 1* (2001) [hereafter *Flaring Emission Factors*], available at <http://www.vcapcd.org/pubs/Engineering/AirToxics/combem.pdf>.

¹²⁷ *Id.*

¹²⁸ See EIA, *Natural Gas Monthly* 3 Tbl. 1 (Sep. 2011), available at <http://www.eia.gov/naturalgas/monthly/>; EIA, Number of Producing Natural Gas Wells, http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm; *Natural Gas Annual 2010* at 1, 4, 6; 76 Fed. Reg. at 52,758.

an annual basis 127,000 tons per year of HAPs,¹²⁹ more than any other TRI-reporting sector, with the exception of Electric Utilities,¹³⁰ and comparable to 29.5 percent of the total air releases of all TRI-reporting sectors in 2010.¹³¹ Breaking down this amount further, the annual BTEX compounds emitted by the industry are between 8,600 and 21,800 tons per year, depending on the source of their emission.¹³²

In terms of specific methods of release, there are four primary pathways: well completions, venting, flaring, and fugitive emissions (i.e., leaks). These are non-exclusive, as a single component in the natural gas production process may very well vent, flare, and leak toxic constituents on a regular basis. Moreover, due to the fact that this is to some extent an exercise in line-drawing, there is a degree of overlap with the category of chemicals used in or resulting from processing discussed below: for example, flaring of gas can occur at the wellhead, and flaring can also occur further along the processing chain.

Some of the most cohesive data on these releases comes from EPA's estimate of per-unit emissions in its promulgation of the final air rule. While these do not provide a holistic, across-the-industry view, they are instructive. For example, as estimated by EPA, the average well completion releases approximately 1.7 tons of HAPs,¹³³ and the average wellhead continues to leak HAPs at a rate of 0.671 tons per year.¹³⁴ These data points in and of themselves are striking, in that they seem to swallow the overall industry emissions estimate of 127,000 tons per year of HAPs. That is, if there are currently 487,627 wells in the U.S. as of 2010, then their average leaks alone would constitute 327,000 tons per year of HAP emissions—nearly three times EPA's overall industry estimate.¹³⁵ Similarly, the average gathering and boosting components leak 3.10 tons of HAPs per year, and the average storage component leaks 0.33 tons of HAPs per year.¹³⁶ Another point worth noting, as discussed below with respect to the Texas emission event data, is that such estimates are often vastly underestimated by orders of magnitude.

Another notable EPA dataset is the extent of emission reductions the final air rule is estimated to achieve on a per-unit basis. While these are emissions *reductions* and therefore by no means reflect the entire emissions of each component of the industry, given that the rule does

¹²⁹ See *Proposed Air Rule Fact Sheet* at 2 (using EPA estimate that a reduction of 38,000 tons per year of HAPs represents “a reduction of nearly 30 percent”).

¹³⁰ *TRI 2010 National Analysis* at B-8.

¹³¹ *Id.* at B-1.

¹³² See *Proposed Air Rule Fact Sheet* at 1; *Gas Composition Memo* at 10 Tbl. 6, 12 Tbl. 9 (using production and well completion weight ratios of BTEX:VOC against total annual VOC emissions).

¹³³ See note 33, *supra*.

¹³⁴ Memorandum from Bradley Nelson & Heather Brown, EC/R Incorporated, to Greg Nizich & Bruce Moore, EPA, Re: *Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Using Emission and Cost Data from the Uniform Standards* 6 Tbl. 2 (April 17, 2012) [hereafter *Equipment Leak Memo*].

¹³⁵ *Id.*; *Natural Gas Annual 2010* at 1 Tbl. 1.

¹³⁶ *Id.*

not achieve total reductions or reductions applicable to all emission sources, they are significant. And although the final air rule is limited to a subset of the industry and does not specifically estimate the emissions reductions per component—e.g., well completion, well leaks, processing plant—a rough estimate can be accomplished by breaking down the total HAP reductions against the total affected facilities. This calculation reveals that, even within the limited unit numbers and limited reductions and application of the Rule, each individual component and process of the industry is responsible for a significant amount of HAP emissions:

Table 1: Emission Reductions under the NSPS Rule.¹³⁷

Source/Emissions Point	Projected No. of Affected Units	Nationwide HAP Reductions (tpy)	HAP Reductions per Affected Unit (tpy)
<i>Hydraulically Fractured Natural Gas Well Completions</i>			
Hydraulically Fractured Gas Wells that Meet Criteria for Reduced Emission Completion ("REC")	4107	6416	1.562
Hydraulically Fractured Gas Well that Do Not Meet Criteria	1377	2151	1.562
<i>Hydraulically Refractured Natural Gas Well Completions</i>			
Hydraulically Refractured Gas Wells that Meet Criteria for REC	532	831	1.562
Hydraulically Refractured Gas Well that Do Not Meet Criteria for REC	121	189	1.562
<i>Equipment Leaks</i>			
Processing Plants	29	5	0.2
<i>Reciprocating Compressors</i>			
Gathering and Boosting Stations	210	15	0.071
Processing Plants	209	41	0.20
<i>Centrifugal Compressors</i>			
Processing Plants	13	9	0.7
<i>Pneumatic Controllers</i>			
Oil and Gas Production	13632	952	0.0698
Processing Plants	15	2	0.1
<i>Storage Vessels</i>			
Emissions at least 6 tpy	304	876	2.88

¹³⁷ RIA at 3-12 Tbl. 3-2, 3-20 Tbl. 3-4.

A similarly notable dataset that demonstrates the amount of TRI-listed chemicals emitted by oil and gas extraction facilities is a recent review of the Texas Commission on Environmental Quality's ("TCEQ") Emissions Event database.¹³⁸ The data is limited to "emissions events" occurring in Texas, which are releases that occur *in addition to* a facility's normal operations. Specifically, these releases tend to be caused by malfunctions, power outages, startup and shutdown activities, and maintenance, and manifest themselves as venting, leaks, and flares.¹³⁹ Because the TCEQ data is based on industry reporting, which often underreports the releases or aggregates the releases under the heading of "natural gas" or "VOCs," the data is inherently incomplete.¹⁴⁰ But even as it stands on its own, it demonstrates that the industry releases a significant amount of HAPs from emissions events alone.

For example, between 2009 and 2011, the state's oil and gas industry reported emissions events releasing 779.01 tons of HAPs.¹⁴¹ 2011 had by far the highest level of emission events, with 633.39 tons of HAPs, and 2010 and 2009 had 68.66 and 79.96 tons, respectively.¹⁴² A few notable data points in particular are the 2009-2011 annual releases of 17.55 tons, 21.69 tons, and 25.76 tons, respectively, by the Boyd compressor station; a 2011 release of 41.28 tons by a Mont Belvieu fractionator; and 2009-2011 annual releases of 1.37 tons, 1.12 tons, and 13.82 tons, respectively, by the Dimmit County compressor station.¹⁴³

In addition to the data presented above, it is important to focus on releases via flaring, due to their prevalence, their significance, and their data limitations. For example, the Energy Information Administration has estimated that, as of 2010, roughly 0.62 percent of all natural gas in the U.S.—or 166 billion cubic feet—is vented or flared.¹⁴⁴ And both this amount and proportion of production have been increasing over the past decade. In 2002, for example, only 99 billion feet of natural gas were vented or flared, or 0.41 percent of the total gas produced.¹⁴⁵

The impacts of this trend are clearer in light of the Ventura County Air Pollution Control District HAP emission factors for flaring, as noted above. When these factors are calculated against the estimated 2010 venting or flaring of 166 billion cubic feet, the amount of each pollutant released is:

¹³⁸ See generally *Accident Prone*.

¹³⁹ *Id.* at 1, 3.

¹⁴⁰ Among other underestimations, industry reporters often provide emission event numbers on the basis of formulas, which understate leak rates from sources such as storage tanks. *Id.* at 8. In fact, a study followed up on a chemical plant's reporting with actual monitoring based on differential absorption light detection and ranging ("DIAL") and found that the actual emissions were greater by an order of magnitude or more. For example, the DIAL measurements found that benzene emissions from storage tanks were 93 times greater than reported, and VOC emissions from other tanks were 132 times greater than reported. *Id.* at 8 Tbl. 5.

¹⁴¹ *Id.*, App. A.

¹⁴² *Id.*

¹⁴³ *Id.*

¹⁴⁴ *Natural Gas Annual 2010* at 1 Tbl. 1.

¹⁴⁵ GAO, *Natural Gas Flaring and Venting: Opportunities to Improve Data and Reduce Emissions* 17 Tbl. 2 (2004).

- Benzene: 26,383 lbs.
- Formaldehyde: 193,970 lbs.
- Polyaromatic hydrocarbons (including naphthalene): 2,323 lbs.
- Naphthalene: 1,825 lbs.
- Acetaldehyde: 7,135 lbs.
- Acrolein: 1,659 lbs.
- Propylene: 404,864 lbs.
- Toluene: 9,624 lbs.
- Xylenes: 4,812 lbs.
- Ethylbenzene: 239,600 lbs.
- Hexane: 4,812 lbs.¹⁴⁶

These are undoubtedly significant amounts of TRI-listed chemicals, but one must also consider that the Ventura County emission factors represent the amount of emissions *after* flaring. That is: (1) some unspecified portion of the emissions in the EIA's combined estimate were vented—not flared—and accordingly a calculation based on *flaring* emission factors likely results in a vast underestimate, given that the long-held industry estimate for flare efficiency (i.e., destruction) is 98 percent; and (2) for the pollutants that were in fact released by flaring, the estimated emissions are also an underestimate of the constituents *actually released*—including the constituents destroyed by flaring—as defined by EPCRA.¹⁴⁷ Accordingly, since the numbers above in fact represent the two percent of constituents *not destroyed* by flaring, each figure should be multiplied by a factor of fifty to estimate the full TRI implications.

In short, emissions of HAPs from oil and gas extraction industry sources are significant, even just from releases of the toxic constituents in natural gas by leaks or flaring. Indeed, many of these numbers surpass TRI thresholds of their own accord. And when combined with the remainder of “normal” emissions that make up the vast majority of industry emissions, there is little question that the industry uses and releases a significant amount of TRI-listed chemicals.

C. Chemicals Used in or Resulting from Processing

As described in detail above, the processing segment of the oil and gas extraction industry seeks to remove impurities and contaminants from the raw natural gas in order to make it high enough quality for transmission to market and distribution to customers. This process involves the use of TRI-listed chemicals to remove these contaminants and results in the release of these chemicals, byproducts of the process, and toxic natural gas constituents.

¹⁴⁶ *Flaring Emission Factors* at 1; *Natural Gas Annual 2010* at 1 Tbl. 1.

¹⁴⁷ Marc McDaniel, Engineering-Science, Inc., Prepared for EPA, *Flare Efficiency Study 5* (1983) [hereafter *Flare Efficiency*], available at http://www.epa.gov/ttn/chief/ap42/ch13/related/ref_01c13s05_jan1995.pdf; *TRI Instructions* at 60, 63 (requiring reporting of waste treatment efficiency in addition to reporting of chemical released).

For this reason, many of the same chemicals noted above are those considered in this category. And as a further matter, EPA has noted without differentiating among categories that air toxics involved with and emitted by the industry include a variety of chemicals, the “most common [of which] are n-hexane and BTEX compounds (benzene, toluene, ethylbenzene and xylenes),” as well as hydrogen sulfide “from production and processing operations that handle and treat ‘sour gas.’”¹⁴⁸ As EPA explained in the supporting documents to the final air rule, “[e]missions of eight HAP make up a large percentage of the total HAP emissions by mass from the oil and gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane.”¹⁴⁹ Moreover, “the main HAP of concern from the oil and natural gas sector [include] benzene, toluene, carbonyl sulfide, ethyl benzene, mixed xylenes, and n-hexane.”¹⁵⁰

In addition to these generally listed toxics, chemicals specific to individual processing techniques and components include:

- Condensate tanks: the liquid mixture of hydrocarbons and aromatic hydrocarbons that is removed from the gas stream and collected in tanks during production includes BTEX compounds;¹⁵¹
- Glycol dehydrators: most dehydrators use glycols for water absorption, including the TRI-listed ethylene glycol.¹⁵² They also emit a significant amount of HAPs, and in particular BTEX compounds, from leaks and venting, as demonstrated in EPA’s data. For example, EPA’s data from the development of the 1999 MACT for large dehydrators revealed that individual dehydrators each emitted dozens of tons of each BTEX compound per year, and the estimated reductions for small dehydrators under the new air rule—with the same qualifier as noted above for considering these merely as *reductions*, not total emissions—demonstrates significant HAP reductions per unit:¹⁵³

Table 2: Emission Reductions under the NESHAP Rule.¹⁵⁴

Source/Emissions Points	Projected No. of Controls Required	HAP Emissions Reductions (tons per year)	HAP Emissions Reductions per Control Required (tons per year)
Production - Small Glycol Dehydrators	74	505	6.8

¹⁴⁸ EPA, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. 52,738, 52,745 (Aug. 23, 2011).

¹⁴⁹ *RIA* at 4-9.

¹⁵⁰ *Id.*

¹⁵¹ Earthworks, Sources of Oil and Gas Air Pollution, http://www.earthworksaction.org/issues/detail/sources_of_oil_and_gas_air_pollution.

¹⁵² *Natural Gas Processing* at 4;

¹⁵³ *See Technology Review Memo*, Attachment 2, Attachment 4.

¹⁵⁴ *RIA* at 3-35 Tbl. 3-9.

Transmission - Small Glycol Dehydrators	7	164	23
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- Gas sweetening: the amine solution process is the most common gas sweetening technique, and one of the amines used is the TRI-listed diethanolamine.¹⁵⁵ Sweetening removes and ultimately results in the production of hydrogen sulfide gas. The hydrogen sulfide that is recovered from the process may be vented, flared, incinerated, or sold as elemental sulfur.¹⁵⁶ Moreover, BTEX compounds are readily absorbed by the amine solution, and sweetening may therefore be a “significant source” of BTEX emissions if the byproducts are released at the process’s end.¹⁵⁷
- Storage tanks: vessels are used for storage and processing needs throughout natural gas processing, and they therefore hold a variety of different TRI-listed chemicals and mixtures thereof. Emissions from the vessels are accordingly significant. For example, EPA’s final air rule estimated an average reduction of 2.88 tons per year of HAPs from each regulated vessel.¹⁵⁸

As expected, the environmental medium of the above releases is primarily, if not wholly, air emissions. And while there is not yet a cohesive set of data for the environmental footprint of natural gas processing, many TRI-listed chemicals are clearly used, and the releases as demonstrated are significant.

D. Chemicals Used in or Resulting from Well Development

The final category is the assortment of chemicals used in or resulting from well development, including in particular the increasingly common and expanding practice of horizontal hydraulic fracturing. Though many of the chemicals involved are the same as those in the categories above, the list is much more extensive and diverse. Moreover, while the toxic constituents of natural gas and the chemicals used in or resulting from processing are primarily released via air emissions, the chemicals used in well development are released to a variety of environmental media, including air, surface and groundwater, underground injection, landfills, wastewater treatment plants, and land application.

¹⁵⁵ *Id.* at 2-3, 2-8; Dow Chemical Co., *Gas Sweetening: Product Specifier 1* (1998), available at http://msdssearch.dow.com/PublishedLiteratureDOWCOM/dh_0039/0901b803800391f8.pdf?filepath=gastreating/pdfs/noreg/170-01395.pdf&fromPage=GetDoc.

¹⁵⁶ See *RIA* at 2-8; EPA, *Stationary Point and Area Sources* 5.3-1 (5th ed. 1995), available at <http://www.epa.gov/ttn/chieff/ap42/ch05/index.html>.

¹⁵⁷ F.D. Skinner et al., *Absorption of BTEX and Other Organics and Distribution Between Natural Gas Sweetening Unit Streams*, Society of Petroleum Engineers (1997), available at <http://www.onepetro.org/mslib/app/Preview.do?paperNumber=00037881&societyCode=SPE>.

¹⁵⁸ *RIA* at 3-12 Tbl. 3-2, 3-20 Tbl. 3-4.

1. The Chemicals Involved

There are a variety of TRI-listed chemicals involved in well development, and one of the best and most recent sources is a 2011 report by the Minority Staff of the U.S. House of Representatives Committee on Energy and Commerce detailing the hundreds of chemicals used by the industry in thousands of products.¹⁵⁹ Though the House Committee report is as exhaustive a summary as we currently have of the variety and extent of chemicals used in the extraction method, the report is inherently limited, as it is based upon voluntary disclosures by oil and gas service companies to the Committee of products and chemicals that they used between 2005 and 2009.¹⁶⁰ Indeed, as the report notes, the companies were unable or unwilling to provide information on the chemical makeup of certain trade secret products.¹⁶¹ This was because in many cases certain products used by the companies were purchased “off the shelf” from suppliers, and the chemical information was not provided to the oil and gas companies.¹⁶² In regard to the considerations under the TRI, however, this has the benefit of meaning that the involvement and use of the chemicals in the report are *admitted* by the industry.

Among the most-used chemicals, based on the number of products in which they appear, three are listed in the TRI: (1) methanol, appearing in 342 products, (4) 2-butoxyethanol (a.k.a. ethylene glycol monobutyl ether), appearing in 126 products, and (5) ethylene glycol, appearing in 119 products.¹⁶³ 2-butoxyethanol is a particularly notable TRI-listed chemical used by the industry, given its human impacts and the fact that EPA has observed the chemical in drinking water wells tested in Pavillion, Wyoming.¹⁶⁴

Although the Committee report did not specifically flag chemicals used by the industry that are listed in the TRI, it did note that twenty-nine of the chemicals used are carcinogens, regulated under the Safe Drinking Water Act for risks to human health, and/or listed as HAPs under the Clean Air Act. These are, in order of the number of industry-used products in which they are found:

- Methanol (Methyl alcohol)
- Ethylene glycol (1,2-ethanediol)
- Diesel
- Naphthalene
- Xylene
- Hydrogen chloride (Hydrochloric acid)
- Toluene
- Ethylbenzene
- Diethanolamine (2,2-iminodiethanol)
- Formaldehyde

¹⁵⁹ *House Committee Report* at 1, 5.

¹⁶⁰ *Id.* at 4-5.

¹⁶¹ *Id.* at 2, 11-12.

¹⁶² *Id.* at 12.

¹⁶³ *Id.* at 6.

¹⁶⁴ *Id.* at 7.

- Sulfuric acid
- Thiourea
- Benzyl chloride
- Cumene
- Nitrilotriacetic acid
- Dimethyl formamide
- Phenol
- Benzene
- Di (2-ethylhexyl) phthalate
- Acrylamide
- Hydrogen fluoride (Hydrofluoric acid)
- Phthalic anhydride
- Acetaldehyde
- Acetophenone
- Copper
- Ethylene oxide
- Lead
- Propylene oxide
- p-Xylene¹⁶⁵

With the exception of diesel, which the Committee listed due to its BTEX constituents, every one of these chemicals is listed under the TRI. And notably, these toxic chemicals appeared in over a quarter of the total products disclosed by industry in the report.¹⁶⁶ In addition to these chemicals, another seventeen identified by the House Report are listed in the TRI, though not specifically flagged by the report:

- Benzyl chloride
- Stabilized aqueous chlorine dioxide
- Propargyl alcohol (2-propyn-1-ol)
- Cyclohexane
- Aluminum oxide (alpha-Alumina)
- 1,2-dibromo-2,4-dicyanobutane
- Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (Dazomet)
- Formic acid
- Butanol
- Aluminum
- Ammonia
- Hydrogen sulfide
- n-Methylpyrrolidone
- 1,2,4-trimethylbenzene
- Ethylene glycol monobutyl ether (2-butoxyethanol)

¹⁶⁵ *Id.* at 8 Tbl. 3.

¹⁶⁶ *Id.*

- Diethylene glycol monomethyl ether
- Di (ethylene glycol) ethyl ether acetate.¹⁶⁷

Another comprehensive listing of the chemicals used by the industry in fracking fluids was conducted by the State of New York's Department of Environmental Conservation as part of its environmental impact statement on the development of Marcellus shale in the state.¹⁶⁸ To compile the list, the state agency drew on Material Safety Data Sheets ("MSDS") provided by the industry. The agency's listing of chemicals included the following TRI-listed chemicals:

- 1, 2, 4-trimethylbenzene
- 1, 4 Dioxane
- 2, 2, Dibromo-3-nitrilopropionamide
- Acrylamide
- Ammonia
- Ammonium nitrate
- Benzene
- Chlorine Dioxide
- Ethyl Benzene
- Ethylene oxide
- Formaldehyde
- Formic acid
- Hydrochloric Acid/Hydrogen Chloride/Muriatic Acid
- Methanol
- Naphthalene
- Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (a.k.a. Dazomet)
- Thiourea
- Toluene
- Xylene¹⁶⁹

While this list does not include chemicals that are used exclusively for drilling,¹⁷⁰ several other sources have examined these constituents. For example, a common weighting agent used in both onshore and offshore drilling muds is barite, which contains primarily barium sulfate but also a host of TRI-listed metals.¹⁷¹ These metals include mercury, cadmium, arsenic, chromium,

¹⁶⁷ See House Committee Report at 13-30; *TRI Instructions*, Table II.

¹⁶⁸ See New York State Department of Environmental Conservation, *Revised Draft Supplemental Generic Environmental Impact Statement, On the Oil, Gas and Solution Mining Regulatory Program: Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs* (2011) [hereafter *N.Y. DEC Revised DSGEIS*], available at <http://www.dec.ny.gov/energy/75370.html>.

¹⁶⁹ *Id.* at 5-55-5-63 Tbl. 5.7.

¹⁷⁰ *Id.* at 5-55 n.55.

¹⁷¹ EPA, *Development Document for Proposed Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas*

copper, lead, nickel, and zinc.¹⁷² And, as discussed in greater detail below, the amount of metals present in the barite will result in regular exceedance of TRI-reporting thresholds by facilities engaged in well development.¹⁷³ Other TRI-listed additives used in drilling and overall well development are:

- Propargyl alcohol, which is a common corrosion inhibitor used in well construction and completion;¹⁷⁴
- 2-butoxyethanol, which is a surfactant used in several phases of well development;¹⁷⁵
- Heavy naptha, which is a lubricant used particularly in drilling muds and contains BTEX compounds and polycyclic aromatic hydrocarbons such as naphthalene;¹⁷⁶
- Halad-344, which is a cementing additive comprised of a modified acrylamide copolymer;¹⁷⁷ and
- Duratone HT, which is a filtration control agent used in drilling fluid systems and contains nonylphenol, a toxic substance that EPA “intends to” add to the TRI, as of August 2010.¹⁷⁸

Inevitably, these additives and their toxic chemical constituents will be present in the drill cuttings and flowback water that reach the surface or remain underground, but there are additional toxic chemicals that are already present in the gas formation and will be mobilized by well development.¹⁷⁹ Within the Marcellus shale formation, these chemicals include lead, arsenic, barium, chromium, uranium, radium, radon, and benzene.¹⁸⁰

Extraction Point Source Category VII-4, VII-6 (1999) [hereafter EPA, Proposed Effluent Limitations for Drilling Fluids].

¹⁷² *Id.* at VII-4.

¹⁷³ See Part IV.B.2.b.i, *infra*.

¹⁷⁴ See Ronald E. Bishop, Ph.D., CHO, to Delaware Riverkeeper Network & Damascus Citizens for Sustainability, *Chemical and Biological Hazards Posed by Drilling Exploratory Shale Gas Wells in Pennsylvania's Delaware River Basin: Report for the Delaware River Basin Commission Exploratory Well Hearing 8* (2010) (on file with Petitioners) (citing Alfa Aesar, *Material Safety Data Sheet acc. to OSHA and ANSI: Propargyl Alcohol* (2008)).

¹⁷⁵ *Id.* (citing Aqua-Clear, Inc., *Material Safety Data Sheet: Airfoam HD* (2005)).

¹⁷⁶ *Id.* at 8-9 (citing American AGIP Co., *Material Safety Data Sheet: Heavy Naphtha* (2006)).

¹⁷⁷ Glenn C. Miller, Ph.D., to Delaware Riverkeeper Network & Damascus Citizens for Sustainability, *Risks Associated with Permitting Exploration Wells in the Delaware River Basin 2* (2010) (on file with Petitioners) (listing additives pursuant to review of MSDS data from permits for eleven well sites in the Delaware River Basin).

¹⁷⁸ See *id.* at 3; Halliburton, *DURATONE® HT: Filtration Control Agent Product Data Sheet* (2010), available at

http://www.halliburton.com/public/bar/contents/Data_Sheets/web/Product_Data_Sheets/D_throu gh_G/DURATONE_HT.pdf; EPA, *Nonylphenol and Nonylphenol Ethoxylates Action Plan Summary*, <http://www.epa.gov/oppt/existingchemicals/pubs/actionplans/np-npe.html>.

¹⁷⁹ See Bishop at 9.

¹⁸⁰ *Id.* at 9-11 (citing Lisa Sumi, Earthworks, *Shale Gas: Focus on the Marcellus* (2008)).

In short, a vast amount of toxic chemicals are regularly involved with the oil and gas extraction industry, and many of the above are reasonably anticipated to be at each oil and gas extraction facility.

2. The Industry's Releases of the TRI-Listed Chemicals Used in or Resulting from Well Development across Environmental Media

The uses and the releases of chemicals used in well development are the most complex to categorize in specific environmental media, given that the media used often depend on the specific companies, sites, and state regulations. As a further matter, there are issues of environmental media overlap, given in particular that many well development chemicals are first injected into the gas well for the purposes of producing the natural gas—rather than disposal—and that a large proportion of these chemicals remain underground in the well and formation or migrate to the surrounding groundwater.¹⁸¹ And the chemicals in the flowback water that reaches the surface may still be released into groundwater by, for example, leaching from “frack pits” or other impoundments. Accordingly, the ultimate medium of groundwater may be due to varying initial media of release.

Groundwater releases are also complicated by regulatory definitional issues. For example, as a matter of statutory definition per the Energy Policy Act of 2005 as discussed below, “the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations” is not considered “underground injection” for the purposes of the Underground Injection Control (“UIC”) program of the Safe Drinking Water Act.¹⁸² While there is no question that a release of toxic pollutants into a natural gas well and/or the surrounding groundwater is a “release” pursuant to EPCRA, the TRI reporting forms currently list the environmental media of wells by UIC classes.¹⁸³ Accordingly, since EPCRA does not exempt such releases, the reporting forms would require clerical revisions. Relatedly, much of the data on the releases below is based on groundwater monitoring, and groundwater itself is not currently listed as an environmental medium on TRI Form R.¹⁸⁴ For these reasons, we will address groundwater and fracking well data under the medium of “other disposal” onsite.¹⁸⁵

First, though, it makes sense to present the general use and release data and analysis on well development chemicals before looking to the individual media. As noted above, EPA already determined in 1996 that the oil and gas extraction sector “conduct[s] significant management activities that involve EPCRA section 313 chemicals.”¹⁸⁶ Similarly, in EPA’s Profile of the Oil and Gas Extraction Industry in 2000, it noted the assortment of chemicals used

¹⁸¹ John A. Veil, Argonne National Laboratory, *Water Management Technologies Used by Marcellus Shale Gas Producers* 13-14 (July 2010) [hereafter *Water Management Technologies*].

¹⁸² See 42 U.S.C. § 300h(d).

¹⁸³ See EPA, *TRI Form R* 2-3 (2011) [hereafter *TRI Form R*], available at <http://www.epa.gov/tri/report/formR/R2011FormR.pdf>; *TRI 2010 National Analysis* at B-1.

¹⁸⁴ *TRI Form R* at 2-3.

¹⁸⁵ *Id.* at 3.

¹⁸⁶ 61 Fed. Reg. at 33,592.

and released by the sector, along with their concentrations and quantities in some cases, which the agency gathered from sources including state agencies.¹⁸⁷

For example, EPA noted that produced water is the largest byproduct by volume, with over 15 billion gallons of water produced annually as of 2000—though undoubtedly much more today.¹⁸⁸ This produced water can contain a variety of toxic chemicals, including: organics such as benzene, naphthalene, toluene, phenanthrene, bromodichloromethane, and pentachlorophenol; inorganics such as lead, arsenic, barium, antimony, sulfur, and zinc; and radionuclides such as uranium, radon, and radium.¹⁸⁹ Drilling wastes—such as drilling fluids and cuttings—are also a large source of waste release for the sector, though much of EPA’s data was limited to offshore oil production.¹⁹⁰ For onshore production, such as gas wells in Pennsylvania’s Devonian formation, EPA found drilling fluids to contain toxic chemicals such as arsenic, barium, lead, manganese, nickel, and silver.¹⁹¹ As noted above, the natural gas production industry has greatly changed since this 1999 data was produced, and drilling fluids now contain many more toxic chemicals.

EPA additionally noted “associated wastes,” which are relatively small in terms of volume but which “are the most likely to contain constituents of concern.”¹⁹² Such constituents include benzene, ethylbenzene, methyl chloride, toluene, fluorine, naphthalene, phenanthrene, and phenol, among others.¹⁹³ Finally, air emissions from the extraction processes can result from leaks, open pits, and other fugitive emissions, and includes a variety of VOCs and polycyclic aromatic hydrocarbons, hydrogen sulfide, fugitive BTEX compounds (i.e., benzene, toluene, ethylbenzene, and xylene), and hydrochloric acid.¹⁹⁴ The industry sector ranked among the top sectors for emissions of VOCs, coming in below only four other sectors.¹⁹⁵

The profile additionally provided another notable data point: a typical production well results in 8.4 to 84 gallons of waste for every vertical foot drilled.¹⁹⁶ Although this amount of waste is not differentiated in terms of TRI-listed versus other waste, even a conservative estimate of well depth—for example, the profile’s 1997 average depth 5,601 feet—would result in roughly 47,000 to 470,000 gallons of waste per well.¹⁹⁷ Given what we know about the industry now, however, this estimate is well out of date. For one, wells are much deeper—between 6,000 and 10,000 feet on average—and include horizontal drilling extending “from 1,000 to 6,000 feet

¹⁸⁷ See *Industry Sector Profile* at 52.

¹⁸⁸ *Id.* at 38.

¹⁸⁹ *Id.* at 39, 54-55.

¹⁹⁰ *Id.* at 56-57.

¹⁹¹ *Id.* at 58.

¹⁹² *Id.* at 41.

¹⁹³ *Id.* at 60.

¹⁹⁴ *Id.* at 45, 63.

¹⁹⁵ *Id.* at 63.

¹⁹⁶ *Id.* at 37.

¹⁹⁷ *Id.* at 17.

or more.”¹⁹⁸ And we also know that companies use upward of 2 to 4 million gallons of water and fracking fluid alone for a single well.¹⁹⁹ Accordingly, the current waste per well may be ten or more times higher than the 2000 estimate. Indeed, as demonstrated below based on data from EPA, the Department of the Interior, and state agencies, the great volumes of drilling and fracking fluids used in well development means that the typical well will use TRI-listed chemicals in exceedance of reporting thresholds.²⁰⁰

a. Groundwater/Other Disposal

As discussed above, much of the recent data on chemicals used in hydraulic fracturing and its associated processes is from the 2011 report by the Minority Staff of the U.S. House of Representatives Committee on Energy and Commerce.²⁰¹ While the report’s reliance on voluntary industry disclosures does lead to limitations, it does provide a good industry-wide estimate for chemicals and volumes injected into hydraulic fracturing wells between 2005 and 2009.²⁰² For example, companies overall used more than 2,500 products containing 750 chemicals and components, with a total volume of 780 million gallons.²⁰³ This volume does not include any water added at the well site—i.e., it does not represent the overall volume of chemical-laden flowback—nor did the chemicals disclosed include any existing toxic chemicals that were mobilized and released as a result of the development process.²⁰⁴ Three of the companies’ top-five most-used chemicals, based on their presence in products, are TRI-listed: (1) methanol, (4) 2-butoxyethanol, and (5) ethylene glycol.²⁰⁵

Additionally, although the Committee did not specifically note TRI-listed chemicals, it provided that twenty-nine of the chemicals disclosed are carcinogens, regulated under the Safe Drinking Water Act, and/or HAPs. With the exception of diesel, as noted above, every one of these toxic chemicals is listed under the TRI.²⁰⁶ And although the Committee report does not provide specific volume information for each of these chemicals, it does provide three useful data points that demonstrate the extent of the industry’s use of such chemicals.

First, as to the carcinogenic chemicals—e.g., naphthalene, xylene, formaldehyde, and thiourea—oil and gas service companies injected 10.2 million gallons of products containing at least one carcinogen between 2005 and 2009.²⁰⁷ Second, with respect to chemicals regulated under the Safe Drinking Water Act—e.g., toluene, ethylbenzene, benzene, and acrylamide—companies injected 11.7 million gallons of products containing one or more such chemicals

¹⁹⁸ See FracFocus, Hydraulic Fracturing: The Process, <http://fracfocus.org/hydraulic-fracturing-how-it-works/hydraulic-fracturing-process>; *OMB Watch Report* at 11.

¹⁹⁹ *OMB Watch Report* at 11.

²⁰⁰ See Part IV.B.2, *infra*.

²⁰¹ *House Committee Report* at 1.

²⁰² *Id.* at 4-5.

²⁰³ *Id.* at 5.

²⁰⁴ *Id.*

²⁰⁵ *Id.* at 6.

²⁰⁶ *Id.* at 8 Tbl. 3.

²⁰⁷ *Id.* at 9.

between 2005 and 2009.²⁰⁸ The vast majority of these fluids, 11.4 million gallons, contained at least one BTEX compound.²⁰⁹ And third, as to HAPs—e.g., methanol, ethylene glycol, hydrogen chloride, and diethanolamine—companies used 595 products containing 24 different HAPs between 2005 and 2009. One company alone used 67,222 gallons of two products containing the HAP and TRI-listed chemical hydrogen fluoride in 2008 and 2009.²¹⁰

Another important industry-level data point worth considering in regard to groundwater releases is the amount of fluids that returns as flowback water and the amount that remains underground. In 2010, the National Energy Technology Laboratory of the U.S. Department of Energy's Office of Fossil Energy commissioned a study examining the water management technologies used by natural gas producers in the Marcellus shale region.²¹¹ In particular, the study found that while the industry has traditionally claimed that thirty to seventy percent of the original fracking fluid volume returns as "flowback water"—i.e., water that flows back upward and exits the well at the surface—reports from Marcellus operators suggest that the actual percentage is in fact much lower, and that most of the volume remains underground "in pores within the formation."²¹² One dataset in particular showed that only about 13.5 percent of the injected fracking fluid is actually recovered.²¹³ When considered against the fact that the average well used 2 to 4 million gallons of water and fracking fluids, as much as 1.73 million to 3.46 million gallons per well may remain—and accordingly are released—underground.²¹⁴

A final and recent consideration is that, in a study released just this summer, Duke University investigated and sampled groundwater in northeastern Pennsylvania and found natural hydraulic pathways between deep underlying formations and shallow groundwater aquifers.²¹⁵ Based on reviews of chemical data of groundwater and hydraulic fracturing brine samples, the researchers found possible migration of Marcellus shale brine through such pathways and concluded that shallow drinking water aquifers in northeastern Pennsylvania are at an increased risk of contamination by brine and other fracturing fluids due to these existing pathways.²¹⁶ That is, even if fluids from fracturing are released thousands of feet below a drinking water aquifer in the Marcellus shale formation—a claim that industry groups use to promote the safety of the practice of hydraulic fracturing—there already exist natural pathways that would allow such fluids or the toxic chemicals therein to migrate upward to drinking water aquifers. In short, the "natural safety" of the thousands of feet between the fracturing site and the drinking water aquifer is nowhere near an absolute. Toxic fluids that are released at the fracturing site may ultimately reach drinking water.

²⁰⁸ *Id.* at 9-10.

²⁰⁹ *Id.* at 10.

²¹⁰ *Id.* at 11.

²¹¹ See *Water Management Technologies* at 3.

²¹² *Id.* at 14.

²¹³ *Id.* at 13.

²¹⁴ *OMB Watch Report* at 11

²¹⁵ Nathaniel R. Warner et al., *Geochemical evidence for possible natural migration of Marcellus Formation brine to shallow aquifers in Pennsylvania*, Proceedings of the Nat'l Academy of Sciences (2012).

²¹⁶ *Id.* at 1, 5.

In addition to this broader, industry-level data, a variety of site-specific incidents, investigations, and actions have occurred over the past several years demonstrating that the industry sector regularly uses and releases many of the toxic chemicals noted above to the medium of groundwater, largely via wells and frack pits. Much of this data comes from two particular investigations undertaken by EPA in Pavillion, Wyoming, and Dimock, Pennsylvania. Several other instances in Texas and Pennsylvania provide additional examples of TRI chemical use and releases by the natural gas extraction industry.

i. Pavillion, Wyoming

EPA undertook its role in Pavillion, Wyoming, due to complaints it received in 2008 from local residents as to the objectionable tastes and odors in their well drinking water, potentially due to natural gas operations—and specifically hydraulic fracturing and storage of fracking wastewater in pits—being conducted in the area.²¹⁷ Accordingly, EPA commenced an investigation, whose objective “was to determine the presence, not extent, of ground water contamination in the formation and if possible to differentiate shallow source terms (pits, septic systems, agricultural and domestic practices) from deeper source terms (gas production wells).”²¹⁸ Thus far, EPA has conducted four rounds of sampling events, each subsequent event of which was due to the detection of contaminants in the previous event.²¹⁹

Specifically, in the first round of sampling in March 2009, EPA tested thirty-five domestic wells and two municipal wells. The results revealed the detection of methane and dissolved hydrocarbons in several of the domestic wells, and EPA accordingly began a second round of samples in January 2010.²²⁰ The second round of sampling tested seventeen domestic wells, four stock/irrigation wells, two municipal wells, and surface water and sediment from a nearby creek.²²¹ Additionally, EPA sampled several sources from the gas production company—Encana—including three shallow groundwater monitoring wells and gas and produced water samples from five production wells.²²²

The second round revealed that seventeen of the nineteen drinking water wells contained total petroleum hydrocarbons, and additional detected compounds included naphthalene, phenols, and methane. Notably, two of the drinking water wells contained compounds above EPA primary drinking water maximum contaminant levels (“MCLs”): one for lead and phthalate, and one for nitrate.²²³ Samples from the gas company’s monitoring wells showed

²¹⁷ See EPA, *Investigation of Groundwater Contamination near Pavillion, Wyoming* xi (DRAFT, Dec. 2011) [hereafter *Pavillion Report*], available at <http://www.epa.gov/region8/superfund/wy/pavillion/>.

²¹⁸ *Id.*

²¹⁹ *Id.* at xi, 5.

²²⁰ *Id.* at 5.

²²¹ *Id.*; see also EPA, *Pavillion, Wyoming Groundwater Investigation, January 2010 Sampling Results and Site Update 1* (Aug. 2010) [hereafter *Pavillion 2010 Update*].

²²² *Id.*

²²³ *Pavillion 2010 Update* at 1.

“high levels of petroleum compounds such as benzene, xylene, methylcyclohexane, naphthalene, and phenol.”²²⁴ EPA noted in conjunction with this finding that the shallow groundwater in which these toxic constituents were detected “is hydrologically connected to the drinking water aquifer.”²²⁵

The detection of “elevated levels of methane and diesel range organics” in deep domestic wells in the second round led EPA to the third and fourth rounds of sampling, in which it installed its own deep monitoring wells—though only two, due to cost constraints—in order to differentiate deep sources of contamination (i.e., gas production wells) from shallow sources (i.e., active and relic wastewater pits).²²⁶ Sampling from these deep monitoring wells revealed “[a] number of synthetic compounds,” including isopropanol (at 212 and 581 µg/L), diethylene glycol (at 226 and 1570 µg/L), triethylene glycol (at 46 and 310 µg/L), and *tert*-butyl alcohol (at 4470 µg/L).²²⁷ These constituents were notable, as EPA was able to link each to a use in the natural gas production process in Pavillion:

- Isopropanol was used in a biocide, in a surfactant, in breakers, and in foaming agents;
- Diethylene glycol was used in a foaming agent and in a solvent;
- Triethylene glycol was used in a solvent;
- *Tert*-butyl alcohol is a known breakdown product of methyl *tert*-butyl ether (a fuel additive) and *tert*-butyl hydroperoxide (a gel breaker used in hydraulic fracturing).²²⁸

With the exception of isopropanol, whose reporting is limited to a certain type of manufacture, each of these is a TRI-listed chemical.

EPA additionally detected a “wide variety of organic chemicals,” including: gasoline range organics, diesel range organics, BTEX compounds, trimethylbenzenes, phenols, naphthalenes, acetone, isopropanol, TBA, 2-butoxyethanol, 2-butanone, diethylene glycol, triethylene glycol, and tetraethylene glycol.²²⁹ Concentrations of these chemicals varied from concentrations measured in µg/L to concentrations of mg/L. Notably, the concentration of benzene in one of the wells exceeded EPA’s primary drinking water MCL by forty-nine times.²³⁰ Specifically, benzene, toluene, ethylbenzene, and xylenes were detected at concentrations of 246, 617, 67, and 750 µg/L, respectively; trimethylbenzenes were detected at 105 µg/L; gasoline range organics were detected at 592 and 3710 µg/L; and diesel range organics were detected at

²²⁴ *Id.*

²²⁵ *Id.*

²²⁶ *Pavillion Report* at 5.

²²⁷ *Id.* at xii.

²²⁸ EPA noted that “Material Safety Data Sheets do not indicate that fuel or *tert*-butyl hydroperoxide were used in the Pavillion gas field,” but that such sheets “do not contain proprietary information and the chemical ingredients of many additives. The source of *tert*-butyl alcohol remains unresolved. However, *tert*-butyl alcohol is not expected to occur naturally in ground water.” *Id.*

²²⁹ *Id.* at 23, 24 Tbl. 3.

²³⁰ *Id.* at 23.

924 and 4050 µg/L.²³¹ Again, EPA linked each of these to a use in the gas production process on site:

- Aromatic solvent (typically BTEX mixture) was used in a breaker;
- Diesel oil (mixture of saturated and aromatic hydrocarbons including naphthalenes and alkylbenzenes) was used in a guar polymer slurry/liquid gel concentrate and in a solvent;
- Petroleum raffinates (mixture of paraffinic, cycloparaffinic, olefinic, and aromatic hydrocarbons) were used in a breaker;
- Heavy aromatic petroleum naphtha (mixture of paraffinic, cycloparaffinic and aromatic hydrocarbons) was used in surfactants and in a solvent;
- Toluene and xylene were used in flow enhancers and a breaker.²³²

Overall, EPA concluded that its sampling results were due to contamination by fracking wastewater pits and the gas wells. Specifically, “detection of high concentrations of benzene, xylenes, gasoline range organics, diesel range organics, and total purgeable hydrocarbons in groundwater samples from shallow monitoring wells near pits indicates that pits are a source of shallow ground water contamination for the area of investigation.”²³³ These results “represent potential broader contamination of shallow ground water.”²³⁴ As to the constituents found in the deep monitoring wells, EPA concluded that “the explanation best fitting the data for the deep monitoring wells is that constituents associated with hydraulic fracturing have been released into the Wind River drinking water aquifer at depths above the current production zone.”²³⁵

Although the Pavillion report is still in draft form, it is the result of years of study and intense analysis by EPA and remains the strongest evidence to date linking the processes and toxic chemicals of hydraulic fracturing to the contamination of groundwater.²³⁶ In fact, the U.S. Geological Survey (“USGS”) recently completed its own study in collaboration with the Wyoming Department of Environmental Quality to assess EPA’s groundwater data and methodology,²³⁷ and the new study largely matches EPA’s data.²³⁸ Specifically, the USGS water chemistry data detected constituents such as diesel-range organics, gasoline-range organics,

²³¹ *Id.* at xii, 24 Tbl. 3.

²³² *Id.* at xii.

²³³ *Id.* at xi.

²³⁴ *Id.* at 33.

²³⁵ *Id.*

²³⁶ Due to concerns from Wyoming as to how the report would affect the operations conducted in the state, EPA has offered to conduct another round of sampling in partnership with the state.

See Mike Soraghan, *Wyo. official pins Pavillion pollution complaints on greed*, E&E News EnergyWire, June 6, 2012, <http://eenews.net/public/energywire/2012/06/06/1>.

²³⁷ See Peter R. Wright et al., USGS, *Groundwater-Quality and Quality-Control Data for Two Monitoring Wells near Pavillion, Wyoming, April and May 2012* 1 (2012), available at <http://pubs.usgs.gov/ds/718/>.

²³⁸ See, e.g., Tom Myers, Ph.D., Technical Memorandum, *Re: Assessment of Groundwater Sampling Results Completed by the U.S. Geological Survey* 1 (Sep. 30, 2012), available at http://www.earthworksaction.org/library/detail/assessment_of_groundwater_sampling_results_completed_by_the_usgs.

benzoic acid, phenol, and acrylonitrile.²³⁹ Further, USGS, like EPA, detected methane, ethane, and propane in the groundwater with ratios and isotopic signatures indicating that the gas source is thermogenic—i.e., from shale formations. Indeed, the gas concentrations have increased since EPA’s study, which suggests that the gas is migrating to the groundwater directly from a fracked shale formation rather than via defective well casing.²⁴⁰ Though USGS has not publicly interpreted its results, an EPA spokesperson has stated that the results are “generally consistent” with EPA’s Pavillion study.²⁴¹

ii. Dimock, Pennsylvania

EPA initiated its involvement in Dimock, Pennsylvania, for similar reasons as those in Pavillion. That is, Dimock residents had noticed contamination of their drinking water shortly after Cabot Oil and Gas Corporation began hydraulic fracturing operations in their vicinity. Initially, the Pennsylvania Department of Environmental Protection (“PA DEP”) secured a consent decree, under which Cabot would provide replacement water to the affected residents. However, when PA DEP released Cabot from these obligations in late 2011, EPA started an “emergency removal action” and began its investigation.²⁴² Over the course of five weeks in early 2012, EPA sampled sixty-one drinking water wells in the Dimock area and released the resulting data in five rounds up through mid-May.²⁴³

Unlike its investigation in Pavillion, EPA has opted not to provide any comprehensive technical analysis of its data beyond statements to the press from a spokesperson.²⁴⁴ As noted above, EIP has performed an analysis based on the data available, and the following TRI-listed chemicals were found present in the wells at levels above MCLs or EPA’s risk-based “trigger

²³⁹ *Id.* at 3-4.

²⁴⁰ *Id.* at 5.

²⁴¹ See Mark Drajem, *Diesel in Water Near Fracking Confirms EPA Tests Wyoming Disputes*, Bloomberg News, Sep. 27, 2012, available at <http://www.businessweek.com/news/2012-09-26/diesel-compounds-found-in-water-near-wyoming-fracking-site>.

²⁴² Memorandum from Richard Fetzer, On-Scene Coordinator, to Dennis P. Carney, Hazardous Cleanup Division, *Re: Action Memorandum – Request for Funding for a Removal Action at the Dimock Residential Groundwater Site, Intersection of PA Routes 29 & 2024, Dimock Township, Susquehanna County, Pennsylvania* (Jan. 19, 2012), available at <http://www.epaosc.org/sites/7555/files/Dimock%20Action%20Memo%2001-19-12.PDF>.

²⁴³ See EPA, Document List, Dimock Residential Groundwater Site, http://www.epaosc.org/site/doc_list.aspx?site_id=7555.

²⁴⁴ See Press Release, *EPA Completes Drinking Water Sampling in Dimock, Pa.*, July 25, 2012, available at <http://yosemite.epa.gov/opa/admpress.nsf/0/1a6e49d193e1007585257a46005b61ad?OpenDocument>. EPA released this seemingly final statement on Dimock in July, and it has provided no indication that it will conduct or offer further analysis other than its conditioned statement that “EPA has determined that there are not levels of contaminants present that would require additional action by the Agency.” *Id.*

levels”: arsenic, barium, chromium, lead, and manganese.²⁴⁵ At least one of these toxic chemicals exceeded MCLs or trigger levels in twelve of the fifty-seven wells for which EPA has provided data—over one-fifth of the wells reported thus far.

Looking more broadly to wells in which TRI-listed chemicals are present in any detectable levels, the number of wells increases to fifty-seven of fifty-seven wells. That is, at least one TRI-listed chemical was found in *every single well* that EPA has reported. In fact, the average number of detections per well was 21, with a maximum of 41 detections and a minimum of five.²⁴⁶ These TRI-listed chemicals are:

- 2-Methoxyethanol
- Acetophenone
- Aluminum
- Anthracene
- Arsenic
- Atrazine
- Barium
- Benzo(a)pyrene
- Bromoform
- Cadmium
- Carbon disulfide
- Chloroethane
- Chloroform
- Chromium
- Cobalt
- Copper
- Cresol-4,6-dinitro-ortho
- Cresol-o
- Cresol-p
- Cyclohexane
- Dibenzofuran
- Dinitrophenol-2,4
- Dinitrotoluene-2,4

²⁴⁵ EPA, Dimock Data Weeks 1-5 (2012), *available at* http://www.epaossc.org/site/doc_list.aspx?site_id=7555 (on file with Petitioners). With EPA’s above-cited press release, it provided additional well data, but this petition’s analysis and results are based on the preceding round of well data reported by EPA on May 15, 2012, which reported data for fifty-seven wells.

²⁴⁶ *Id.* Each well had multiple samples for each chemical constituent—including, for example, one regular sample, one filtered sample, one sample from the kitchen faucet, and in some cases duplicate samples—so the number of detections per well does not necessarily signify the number of individual chemicals detected. See EPA, *Key to EPA Validated Data Summary Report Dimock Residential Sampling 1*, *available at* <http://www.epaossc.org/sites/7555/files/glossary-key.pdf>.

- Ether, bis(2-chloroethyl)
- Fluoranthene benzo(k)
- Fluoranthene-benzo(b)
- Freon 113
- Hexachlorobenzene
- Hexachloroethane
- Lead
- Lithium
- m,p-Xylene
- Manganese
- Methyl bromide
- Methyl chloride
- Methyl tertiary butyl ether (MTBE)
- Naphthalene
- Nickel
- Nitrogen, Nitrite + Nitrate
- Nitrophenol-4
- Nitrosodimethylamine-n
- Nitrosodiphenylamine-n
- Perylene-benzo(ghi)
- Phenanthrene
- Phenol
- Phthalate, bis(2-ethylhexyl) (DEHP)
- Phthalate, Dimethyl
- Propylamine,n-nitroso di-n-
- Pyrene-indeno(1,2,3-cd)
- Selenium
- Styrene
- Tetrachloroethylene
- Toluene
- Vanadium
- Xylene-o
- Zinc²⁴⁷

The presence of these TRI-listed chemicals in *every* Dimock well reported is significant in and of itself, but it should additionally be noted that the sampling methodology was flawed such that EPA may have missed toxic chemical whose concentrations—and, indeed, MCLs—fell below the sampling’s minimum detection limits.²⁴⁸ Such TRI-listed chemicals include: 1,2-dibromoethane, atrazine, hexachlorobenzene, pentachlorophenol, and 1,2-dibromo-3-chloropropane (DBCP). Given that many of the TRI-listed chemicals regularly used in hydraulic

²⁴⁷ *Id.*

²⁴⁸ *Id.*

fracturing and related processes are toxic in small amounts, the investigation is not complete without further and more sensitive well testing.²⁴⁹

iii. Other Incidents and Investigations

Beyond the in-depth investigations and studies of Pavillion and Dimock, a number of other instances have occurred in the past few years in which natural gas extraction operations have released toxic chemicals into the environment, including the following:

- Range Resources, Texas (2010): EPA brought emergency action under the Safe Drinking Water Act against Range Resources in 2010 for its hydraulic fracturing operation's contamination of drinking water wells with TRI-listed chemicals in the vicinity of Fort Worth, Texas.²⁵⁰ EPA took this emergency action due to "elevated levels of benzene, toluene, ethane, and a high level of methane (measured at that time at 7,810 µg/L [and later 20,100 µg/L])" in one domestic drinking water well and "elevated levels of methane, ethane, and propane in another nearby residential water supply well."²⁵¹ EPA determined that "the presence of gas in Domestic Well 1 is likely to be due to impacts from gas development and production activities in the area," and brought an emergency administrative order against Range Resources due to "its concern that methane and benzene contamination (among other contaminants) 'may present an imminent and substantial endangerment to the health of persons.'"²⁵² Specifically, "EPA based this determination on its concern that 'methane in the levels found by EPA are potentially explosive or flammable, and benzene if ingested or inhaled could cause cancer, anemia, neurological impairment and other adverse health impacts.'"²⁵³ Other toxic chemicals identified by EPA's well sampling included cyclohexane and toluene.²⁵⁴ Additionally, EPA found a number of gases in the residents' well water, including methane, ethane, propane, iso-butane, and n-butane, further indicating that the contamination had come from natural gas extraction.²⁵⁵
- Cabot, Faulty Well Casing and Other Violations, Pennsylvania (2009-2012): In September 2011, PA DEP sent a Notice of Violation letter to Cabot, based on instances in which Cabot's faultily constructed well casing—which, as discussed above, is responsible for preventing the substances traveling up and down the well from reaching

²⁴⁹ See Pennsylvania Environmental Solutions Conservation, Alternative Energy, Sustainability, HW-16 Methane Boron Barium Acetone Ketone, Strontium, Iron, Manganese, Biogenic, <http://pennsylvania-solutions.blogspot.com/2012/05/hw-16-methane-boron-barium-acetone.html>.

²⁵⁰ See *United States v. Range Production Co.*, 793 F. Supp. 2d 814, 816-17 (N.D. Tex. 2011).

²⁵¹ See United States' Memorandum in Opposition to Defendants' Motion to Dismiss at 3, *Range Production Co.*, 793 F. Supp. 2d 814 (No. 3:11-CV-00116-F).

²⁵² *Id.* (quoting Emergency Administrative Order).

²⁵³ *Id.*

²⁵⁴ See Administrative Record at 2, *Range Production Co.*, 793 F. Supp. 2d 814 (No. 3:11-CV-00116-F), available at

http://www.epa.gov/region6/6xa/pdf/administrative_record_range_011311.pdf.

²⁵⁵ *Id.* at 1.

the surrounding drinking water aquifer—led to methane contamination of three drinking water wells.²⁵⁶ And this was far from the first time that Cabot had been put on notice as to contamination caused by its faulty well casings: in late 2009, the Department reached a consent order with Cabot over faulty well construction and a series of releases of drilling muds and other fluids, under which Cabot would pay the largest fine in state history and most importantly establish a plan to ensure the integrity of its well casings.²⁵⁷ Given that Cabot's well casings failed again less than two years later, despite the large fine and order the company was under to ensure well integrity, it is clear that even operators under close scrutiny may fail to ensure that well integrity is maintained.

- Various Releases, Various States: in the above-cited report recently released by OMB Watch, numerous other site-specific releases are described or cited, showing—in combination with these handful of investigations and incidents described herein—that the oil and gas extraction sector routinely uses and regularly releases significant amounts of TRI-listed chemicals.²⁵⁸

b. Surface Water Discharges

The data on surface water releases of chemicals used in well development lacks the same detail of study and investigation, but a couple of recent site-specific incidents provide examples of the impacts:

- Chesapeake Energy, Pennsylvania/Maryland (2011): In 2011, the Attorney General for the State of Maryland sent a notice of intent to sue Chesapeake Energy Corporation under the Clean Water Act and the Resource Conservation and Recovery Act due to a “blowout” of one of Chesapeake's wells that released tens of thousands of gallons of fracking fluids containing toxic chemicals onto farm fields and into a tributary of the Susquehanna River.²⁵⁹ PA DEP ultimately exercised its authority to enforce against Chesapeake, thereby barring Maryland's suit, and ultimately reached a consent order and agreement with Chesapeake.²⁶⁰ Although Chesapeake never revealed the extent of chemicals present in the released fluids, PA DEP performed limited testing that found

²⁵⁶ See PA DEP, Notice of Violation, Re: Gas Migration Investigation 1-2 (Sep. 19, 2011), available at <http://shale.sites.post-gazette.com/images/stories/CabotMethaneViolationNov11.pdf>.

²⁵⁷ See PA DEP, Consent Order and Agreement (Nov. 4, 2009), available at http://s3.amazonaws.com/propublica/assets/natural_gas/final_cabot_co-a.pdf; Sabrina Shankman, *Pennsylvania Tells Drilling Company to Clean Up Its Act*, ProPublica, Nov. 6, 2009, <http://www.propublica.org/article/pennsylvania-tells-drilling-company-to-clean-up-its-act-1106>.

²⁵⁸ See OMB Watch Report at 14-17.

²⁵⁹ See Press Release, Md. Office of the Attorney General, *Attorney General Gansler Notifies Chesapeake Energy of the State's Intent to Sue for Endangering the Health of Citizens and the Environment*, <http://www.oag.state.md.us/Press/2011/050211.html>.

²⁶⁰ PA DEP, Consent Order and Agreement 2 (Feb. 3, 2012), available at http://files.dep.state.pa.us/RegionalResources/NCRO/NCROPortalFiles/Atgas_COA_FINAL.pdf

barium at concentrations of 5860 mg/L at the site of discharge, 1190 mg/L at the mouth of the receiving tributary, and at 45.5 mg/L downstream in Towanda Creek. Pennsylvania's water quality standards limit barium to 21 mg/L maximum and to 2.4 mg/L for human health criteria.²⁶¹

- Cabot Oil and Gas Corporation, Pennsylvania (2009): A series of three spills of liquids including a “gel-like lubricant” occurred over the course of a week in 2009 at the Cabot Heitsman well site in Dimock, Pennsylvania. According to PA DEP, the spills polluted a wetland and caused a fish kill.²⁶² The spills released 8,000 gallons of the substance in total and resulted in a fine of \$56,500 and a temporarily ordered shutdown of all fracturing operations by the company in the county.²⁶³ The Department allowed Cabot to begin operations in the county several weeks later.²⁶⁴ While Cabot never fully revealed the chemical composition of the released substances, it did eventually release the material safety data sheet (“MSDS”) for the gel used—LGC-35 CBM, a fracking gel concentrate produced by Halliburton—as part of its agreement with the Department.²⁶⁵ The MSDS did not reveal the chemical constituents of LGC-35 CBM beyond stating that it contained 30-60 percent “polysaccharide” and 30-60 percent “paraffinic solvent.”²⁶⁶ And although the MSDS noted that the gel was a “[p]otential carcinogen” that may have “central nervous system effects” and potentially fatal other effects, it claimed that the gel did “not contain a toxic chemical for routine annual ‘Toxic Chemical Release Reporting under Section 313.’”²⁶⁷ Nonetheless, every single human toxicity test (e.g., oral toxicity, carcinogenicity) and item of ecological information (e.g., mobility, bioaccumulation) was listed as “not determined.”²⁶⁸ A 2007 investigation by the U.S. House of Representatives

²⁶¹ *Id.* at 3.

²⁶² George Basler, *Pa. orders shutdown of Cabot drilling*, Press Connects, Sep. 25, 2009, <http://www.pressconnects.com/article/20090925/NEWS01/909250390/Pa-orders-shutdown-Cabot-drilling>.

²⁶³ Press Release, PA DEP, *Pennsylvania DEP Fines Cabot Oil and Gas Corp. \$56,650 for Susquehanna County Spills*, <http://www.prnewswire.com/news-releases/pennsylvania-dep-fines-cabot-oil-and-gas-corp-56650-for-susquehanna-county-spills-65589387.html>.

²⁶⁴ *Id.*

²⁶⁵ See URS Corp., Engineering Study, For Submittal To: Pennsylvania Department of Environmental Protection, In Response To: Order Dated September 24, 2009, Prepared For: Cabot Oil & Gas Corporation, Attachment 3 (October 9, 2009).

²⁶⁶ *Id.*

²⁶⁷ *Id.*

²⁶⁸ *Id.* Halliburton revised the MSDS for LGC-35 CBM in 2010 to strike “potential carcinogen,” but it still has yet to disclose the actual chemical components, and every ecological and toxicity test remains “not determined.” See Halliburton, Material Safety Data Sheet, LGC-35 CBM at 1, 4 (2010); see also Steve Coffman, Committee to Preserve the Finger Lakes, *The Safety of Fracturing Fluids: A Quantitative Assessment* (Aug. 4, 2009), available at <http://shaleshock.org/2009/08/the-safety-of-fracturing-fluids-%E2%80%93-a-quantitative-assessment/>; George Monk & Molly Schaffnit, *Fracture Gel's Possible Synergistic Influence for Chloride's Effects on Vegetation* 4 (Nov. 2011), available at http://members.citynet.net/sootypaws/gws/documents/gel_synergy.pdf.

Committee on Oversight and Reform flagged Halliburton in particular for using diesel and BTEX chemicals in its fracking fluids and for not specifying in its disclosure to the Committee as to “whether the company used fracturing fluids containing diesel in coalbed methane wells located within underground sources of drinking water, as prohibited by [an EPA memorandum of agreement].”²⁶⁹

In addition to these incidents, a few regulatory and environmental medium issues are noteworthy. First, as noted below, the Clean Water Act has long exempted from definition as a pollutant any material injected for the production of oil or gas, with some provisos.²⁷⁰ While this may have made sense to avoid regulatory overlap with the Safe Drinking Water Act’s regulation of underground injection, the Energy Policy Act recently exempted oil and gas production wells from such regulation and opened a much wider regulatory gap. The Energy Policy Act additionally redefined “oil and gas exploration and production” to completely exempt all such activities, whether including construction or not, from coverage by the Clean Water Act’s regulation of stormwater pollution.²⁷¹ Accordingly, there are significant regulatory gaps as to surface water pollution by the oil and gas extraction industry.

Second, there is some environmental medium overlap between surface water and fracking waste sent to wastewater treatment plants, as discussed below. When such plants are unable to properly treat such wastes, the inevitable result is surface water pollution.

c. Transport to Wastewater Treatment Plants

A recently significant medium of release for well development chemicals is via transport to a municipal or commercial/industrial wastewater treatment plant. Again, this is a medium under which detailed data is limited, but the shortcomings of this type of treatment and the accordant impacts are becoming apparent, to the extent that EPA and state authorities are beginning to place conditions on or prohibit the disposal of oil and gas industry wastewater at such facilities.²⁷²

Specifically, wastewater treatment plans are unable to prevent the discharge of toxic chemicals to surface water—i.e., municipal wastewater treatment plants are not equipped to

²⁶⁹ See Memorandum from Chairman Henry A. Waxman and Subcommittee Chairman Edward J. Markey, U.S. House of Representatives Committee on Energy and Commerce, to Members of the Subcommittee on Energy and Environment 7-8 (Feb. 18, 2010) [hereafter *Subcommittee on Energy and Environment Memorandum*].

²⁷⁰ 33 U.S.C. § 1362(6)(B).

²⁷¹ See 33 U.S.C. §§ 1362(6)(B), 1342(l)(2).

²⁷² See, e.g., Deborah Solomon, *Agency to Set Standards on Fracking Waste Water*, Wall Street Journal, Oct. 21, 2011 (“EPA said many treatment plants ‘are not properly equipped to treat this type of waste water,’ and said it would consider standards that must be met before water can be sent to a treatment facility.”), available at <http://online.wsj.com/article/SB10001424052970203752604576643440443268466.html>.

properly remove certain constituents, like salts and radioactive materials²⁷³—so any such transport to a municipal wastewater treatment plant (itself a reportable release under the TRI) will also result in a release of that chemical to surface waters.

In terms of data on specific releases, the above-cited waste management technologies study by the National Energy Technology Laboratory does provide some aggregated information on disposal of flowback and produced waters to both municipal and commercial/industrial wastewater treatment plants by natural gas producers in the Marcellus shale region.²⁷⁴ In Pennsylvania alone, as of 2010, twenty-seven commercial wastewater treatment facilities were permitted by PA DEP to treat flowback and produced water and then discharge this treated water to surface waters. Four other commercial wastewater treatment facilities treated the water and then discharged it to municipal wastewater treatment plants. And twenty-five other commercial wastewater treatment facilities had applied for permits to operate and discharge, but had not yet received permission as of the time of the report.²⁷⁵

Earlier but more specific data showed that, between 2005 and 2006, the following commercial wastewater treatment plants accepted flowback and produced water, in the following volumes and rates:

Table 3: Pennsylvania Facilities Accepting Wastewater from Oil and Gas Operations.²⁷⁶

Disposal Facility Name	Location	Throughput Capacity
Castle Environmental Inc.	New Castle, PA	Daily volume on 6/28/10 was ~260,000 gal/day; this was slightly lower than average
Hart Resource Technologies	Creekside, PA	18,000 gal/day of produced water; 45,000 gal/day of flowback; total from 11/08 to 10/09 = 23.2 million gal
Pennsylvania Brine Treatment	Franklin, PA	140 gpm; total from 11/08 to 10/09 = 53 million gal
Tunnelton Liquids	Saltsburg, PA	Total of 1 million gal/day; ~100,000 gal/day of oil and gas water; ~900,000 gal/day of acid mine drainage

²⁷³ See, e.g., Rebecca Hammer & Jeanne VanBriesen, Ph.D., PE, Natural Res. Def. Council, *In Fracking's Wake: New Rules are Needed to Protect Our Health and Environment from Contaminated Wastewater* 73-75 (2011), available at <http://www.nrdc.org/energy/files/Fracking-Wastewater-FullReport.pdf>.

²⁷⁴ *Water Management Technologies* at 19-23.

²⁷⁵ *Id.* at 20.

²⁷⁶ *Id.* at 22 Tbl. 2; see also *id.* App. A (listing all existing and proposed wastewater treatment plants in Pennsylvania accepting oil and gas production wastes).

Most recently, PA DEP has requested a voluntary cessation on disposal of flowback and produced water at the remaining municipal sewage and commercial treatment plants that accepted the wastes, due to the wastes' significant contributions of high concentrations of bromides to rivers and streams used as drinking water sources.²⁷⁷ While the bromides themselves do change the salinity of the receiving water, the larger problem is that when that water is treated to become drinking water, the disinfectants used by water treatment plants react with the bromides to form trihalomethanes ("THMs").²⁷⁸ Studies have found a link between THMs and several types of cancer and birth defects via ingestion and exposure.²⁷⁹ Indeed, THMs listed under the TRI and resulting from bromides include bromoform and dichlorobromomethane.²⁸⁰

As noted below, the voluntary cessation resulted in a vast increase in the disposal of liquid wastes via injection wells in Ohio. Though full numbers are not available, prior to the cessation, eight wastewater treatment facilities on the Allegheny River were allowed to discharge "an average of 1.5 million gallons of Marcellus drilling wastewater and hydraulic fracturing fluid a day," another three facilities on the Monongahela River discharged a total of 185,000 gallons a day, and another 650,000 gallons were discharged into the Ohio River and its tributaries from wastewater treatment facilities.²⁸¹

d. Disposal by Injection Well

Another medium of release is via disposal in injection wells. As noted above, while the injection of fluids in the process of hydraulic fracturing is exempt from coverage under the Safe Drinking Water Act, and accordingly is not currently listed as a release medium due to its categorization by UIC well class, injection wells for the *disposal* of oil and gas waste are covered by the Act as Class II injection wells.²⁸² Given the vast amount of liquids used in and resulting from hydraulic fracturing, these wastewater injection wells have become increasingly common in the Marcellus region for the disposal of flowback water and produced water.²⁸³

Nationwide, there are roughly 144,000 injection wells for the disposal of well development wastes, and such wells have rapidly proliferated in Ohio in recent years due to its

²⁷⁷ See Don Hopey & Sean D. Hamill, *DEP asks drillers to stop disposing wastewater at plants*, Pittsburgh Post-Gazette, April 20, 2011, available at <http://old.post-gazette.com/pg/11110/1140547-503-0.stm>.

²⁷⁸ *Id.*; Don Hopey, *Bromide: A concern in drilling wastewater*, Pittsburgh Post-Gazette, March 13, 2011, available at <http://old.post-gazette.com/pg/11072/1131660-113.stm>;

²⁷⁹ *Id.*

²⁸⁰ *TRI Instructions* at II-4, II-5.

²⁸¹ Don Hopey, *Bromide: A concern in drilling wastewater*, Pittsburgh Post-Gazette, March 13, 2011.

²⁸² See EPA, *Class II Wells - Oil and Gas Related Injection Wells (Class II)*, <http://water.epa.gov/type/groundwater/uic/class2/index.cfm>.

²⁸³ *Water Management Technologies* at 14-15.

proximity to Pennsylvania hydraulic fracturing operations.²⁸⁴ For example, a 2009 survey of Ohio wells found that most accepted wastewater for injection in quantities of tens of thousands to hundreds of thousands barrels per year, with the total amount injected across all Ohio injection wells as 4,467,913 barrels—or 187,652,346 gallons.²⁸⁵ In 2011, by contrast, Ohio's wells accepted 12 million barrels of waste, or 504 million gallons—nearly three times the 2009 amount.²⁸⁶ And as of early 2012, Ohio has 194 such wells.²⁸⁷

A unique side effect of disposal of well development wastes in injection wells—and one that is illustrative of the connection and interchangeability among the various environmental media of release—is the recently demonstrated strong correlation with earthquakes in the vicinity of the wells.²⁸⁸ In fact, after a series of earthquakes near Ohio injection wells outside of Youngstown, the state halted injections in a five-mile radius of one well pending further study.²⁸⁹ This cessation followed a similar moratorium by Arkansas in 2010 and an earlier study on Texas wells and earthquakes.²⁹⁰ Use of Ohio injection wells for the disposal of liquid well development wastes had rapidly increased in the months prior to the earthquakes, due in large part to a similar call by Pennsylvania for a cessation of disposal of such wastes at wastewater treatment plants.²⁹¹ Since Pennsylvania oil and gas companies had been disposing of ninety-five percent of their liquid wastes at such plants, they very quickly turned to Ohio injection wells for their disposal needs.²⁹²

e. Disposal in Landfills

Another medium of release for solid wastes resulting from well development is via landfill disposal. Well development involves a significant amount of solid waste—in addition to the vast amounts of liquid waste and air emissions—and this tends to be the dividing line as to what is disposed of in a landfill versus what is injected, sent to a wastewater treatment plant, or otherwise discharged. As discussed above, one of the primary categories of solid waste is drill cuttings, which include a variety of toxic constituents, both from contact with drilling fluids and additives and toxic chemicals that are already present in the gas formation.²⁹³ TRI-listed chemicals in drilling additives include 2-butoxyethanol, nonylphenol, and propargyl alcohol, and

²⁸⁴ Scott Detrow, *Explaining Pennsylvania's Link To Ohio Earthquakes*, NPR StateImpact, April 4, 2012, <http://stateimpact.npr.org/pennsylvania/2012/04/04/pennsylvanias-link-to-ohio-earthquakes/>.

²⁸⁵ *Water Management Technologies* at 16-17, Tbl. 1.

²⁸⁶ Scott Detrow, *Explaining Pennsylvania's Link To Ohio Earthquakes*, NPR StateImpact, April 4, 2012.

²⁸⁷ Daniel Gilbert, *Ohio Shuts Wells Following Quakes*, Wall St. J., Jan. 3, 2012, available at <http://online.wsj.com/article/SB10001424052970203462304577136920749123772.html>.

²⁸⁸ Press Release, *Study Finds Correlation Between Injection Wells and Small Earthquakes*, Aug. 6, 2012, <http://www.utexas.edu/news/2012/08/06/correlation-injection-wells-small-earthquakes/>.

²⁸⁹ Daniel Gilbert, *Ohio Shuts Wells Following Quakes*, Jan. 3, 2012.

²⁹⁰ *Id.*

²⁹¹ *Id.*

²⁹² *Id.*

²⁹³ See Bishop at 9.

naturally occurring toxic chemicals mobilized by drilling include lead, arsenic, barium, chromium, uranium, radium, radon, and benzene.²⁹⁴

Data on landfill disposal of well development wastes is still developing, but certain documented actions by regulatory agencies and landfills demonstrate the variety of and limits on accepted wastes. For example, the Ohio Environmental Protection Agency recently released guidance stating that drill cuttings may be disposed of in offsite licensed solid waste landfills, even to the extent that the cuttings contained naturally occurring radioactive materials (“NORMs”) or had come into contact with drilling muds.²⁹⁵ The agency also noted that it did not consider the cuttings to be a hazardous waste and also that “drill cuttings do not come in contact with any chemicals used in the hydraulic fracturing process.”²⁹⁶

The actions of individual landfills also demonstrate the characteristics of wastes sent to the landfills and the limitations of landfills and state regulatory agencies in handling such wastes. In North Dakota, for example, municipal landfills have begun to reject filters used to strain wastewater from oil wells and empty bags used to haul fracking sand due to their low-level radioactivity.²⁹⁷ One municipal landfill owner had rejected twenty-three loads due to such exceedances of allowable radioactivity, and a state official indicated that four special waste facilities had also turned away loads.²⁹⁸ Notably, the landfill owner indicated that “he doesn’t know where the rejected loads are going and [Scott Radig, who manages the state’s solid waste programs] said the state doesn’t have a manifest or tracking system to follow those truck loads.”²⁹⁹ The increased radioactivity of the fracking sand may be due to the recent use of “fracking sand from China made from aluminum oxide ore,” and additional radioactive solid wastes include bottom sludge from oil tanks and scale from oil pipe.³⁰⁰

Similarly, municipal and private landfills in Kansas have been encountering attempted disposal of mud from fracking operations, which the landfills are unable to accept due to its high liquid content.³⁰¹ The liquid content can lead to the materials leaching into the soil, which is

²⁹⁴ *Id.* at 9-11 (citing Lisa Sumi, Earthworks, *Shale Gas: Focus on the Marcellus* (2008); Miller, *supra* note 177, at 2-3.

²⁹⁵ Ohio EPA, *Fact Sheet: Drill Cuttings from Oil and Gas Exploration in the Marcellus and Utica Shale Regions of Ohio* 1-2 (Feb. 2012).

²⁹⁶ *Id.* at 1. These semantics as to “contact with fracking fluids” seem somewhat obfuscatory, or at least arbitrary, given that drill cuttings regularly come into contact with drilling fluids, which contain toxic constituents, as detailed above.

²⁹⁷ See Lauren Donovan, *Oilfield wastewater filters rejected at landfills for radioactivity*, Bismarck Trib., Jan. 13, 2012, available at http://bismarcktribune.com/news/state-and-regional/oilfield-wastewater-filters-rejected-at-landfills-for-radioactivity/article_fa63b5c4-3e3d-11e1-9bd5-001871e3ce6c.html#ixzz1jSgwz4F9.

²⁹⁸ *Id.*

²⁹⁹ *Id.*

³⁰⁰ *Id.*

³⁰¹ Gale Rose, *Landfills refusing sludge from fracking wells*, Pratt Trib., June 16, 2012, available at <http://www.pratttribune.com/news/x996540692/Landfills-refusing-sludge-from-fracking-wells>.

particularly a problem for smaller landfills that lack liners and do not traditionally handle such wastes.³⁰² However, with the recent increase in hydraulic fracturing operations, more wastes are being generated, and more landfills are dealing with such wastes for the first time.³⁰³

All of these recent events underline an additional regulatory shortcoming discussed in greater detail below: since a decision by EPA in 1988 not to regulate wastes from the oil and gas extraction industry as hazardous and several decades of inaction since, regulation has largely been left to each state.³⁰⁴ With more states involved in the oil and gas extraction industry, whether hosting production or disposal facilities, the extent to which this waste and its toxic chemicals are controlled will vary greatly.

f. Releases via Air Emissions

A final environmental medium of release for toxic constituents involved in well development is via air emissions. While the seemingly most obvious sources of emissions from the oil and gas industry are with respect to natural gas constituents and processing, as discussed above, a vast quantity of emissions also result from the open “frack pits” (also known as “produced water ponds”) and other such impoundments that hold fracking fluids, flowback water, and produced water, as well as from leaks, venting, and evaporative loss from the tanks that may also hold these substances.³⁰⁵ As the pits, in particular, are typically open to the air, the volatile chemicals contained in the fluids—such as the BTEX compounds and hydrogen sulfide—will inevitably evaporate and escape into the air.³⁰⁶ For obvious reasons, data on these emissions is developing, but the data available and extent of chemicals involved in the fluids give some idea of the emissions involved.

As a general matter, EPA stated in the Proposed Air Rule that it “believes that produced water ponds are . . . a potentially significant source of emissions,” and specifically sought comments on control options for such ponds.³⁰⁷ As Petitioner Sierra Club stated in comments on the Proposed Air Rule, this produced water can produce significant VOC emissions, and EPA’s own research has demonstrated that such open-air impoundments can emit HAPs such as the BTEX compounds and methanol.³⁰⁸

In fact, the New York Department of Environmental Conservation has also gathered data on such emissions and concluded that the impoundments could be significant sources of methanol:

³⁰² *Id.*

³⁰³ *Id.*

³⁰⁴ See Part IV.A.2, *infra*.

³⁰⁵ See Earthworks, Sources of Oil and Gas Air Pollution, http://www.earthworksaaction.org/issues/detail/sources_of_oil_and_gas_air_pollution.

³⁰⁶ *Id.*

³⁰⁷ See 76 Fed. Reg. at 52,756.

³⁰⁸ See Eben Thoma, *Measurement of Emissions from Produced Water Ponds: Upstream Oil and Gas Study #1* (2009), available at <http://permanent.access.gpo.gov/lps120786/600r09132.pdf>.

Analysis of air emission rates of some of the compounds used in the fracturing fluids in the Marcellus Shale reveals potential for emissions of hazardous air pollutants (HAPs), in particular methanol, from the recovered (flowback) water stored in central impoundments. This methanol is present as a major component of the surfactants, cross-linker solutions, scale inhibitors and iron control solutions used as additives in the frac water. Current field experience indicates that an approximately 25% recovery of fracturing water from Marcellus shale wells may be expected. Thus, using a 25% recovery factor of a nominal 5,000,000 gallons of frac water used for each well, an estimated 6,500 pounds (3.25 tons) of methanol will be contained in the flowback water. Since methanol has a relatively high vapor pressure, its release to the atmosphere could possibly occur within only about two days after the recovered water is transferred to the impoundment. Based on an assumed installation of ten wells per wellsite in a given year, an annual methanol air emission of 32.5 tons (i.e., “major” quantity of HAP) is theoretically possible at a central impoundment.³⁰⁹

The estimate of 6,500 pounds of methanol is in and of itself significant, but it is important to recognize that: (1) this is only twenty-five percent of the methanol *used* per well for the purposes of TRI thresholds and reporting, and (2) there are undoubtedly many of the other chemicals noted above present in the flowback water. That is, a single well in the Marcellus shale region may actually use and, into several environmental media, release *26,000 pounds of methanol alone*—well above the TRI reporting threshold.

E. Chemical Risks and Health Effects

Though the risks and health effects of each the TRI-listed chemicals associated with the oil and gas extraction industry could be discussed in depth,³¹⁰ we describe a few in particular here, primarily based on EPA’s own analysis in the regulatory impact analysis of the final air rule, in which EPA flagged the following as “the main HAP[s] of concern”: benzene, toluene, ethylbenzene, xylenes, carbonyl sulfide, and n-hexane.³¹¹ These chemicals are additionally very common to the industry, and most are released both by emissions and releases to water. We additionally describe hydrogen sulfide, which is another air pollutant released by the industry in

³⁰⁹ New York State Department of Environmental Conservation, *Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Program* § 6.5.1.8 (Sep. 30, 2009). The Department’s recent revised environmental impact statement, as cited above, has deleted this statement, not on the basis of its veracity, but rather on the grounds that “[t]he Department was informed in September 2010 that operators would not routinely propose to store flowback water either in reserve pits on the well pad or in centralized impoundments” and therefore opted not to address such practices in the revised draft. See *N.Y. DEC Revised DSGEIS* § 1.1.1.1.

³¹⁰ For a wider description of the human health impacts of the many toxic chemicals used by the industry, see Theo Colborn et al., *Natural Gas Operations from a Public Health Perspective*, 17 *Hum. & Ecological Risk Assessment: An Int’l J.* 1039, 1045-49 (2011).

³¹¹ *RIA* at 4-14.

well development, production, and processing, and which EPA recently added to the TRI, with the 2012 reporting year as the first year of implementation.³¹²

1. Benzene

Nationwide, benzene is one of the two “key pollutants that contribute most to the overall cancer risks.”³¹³ It is a known human carcinogen “by all routes of exposure”—specifically causing leukemia—and also has serious non-cancer effects, such as preleukemia, aplastic anemia, and “the depression of the absolute lymphocyte count in blood.”³¹⁴ Though most of these non-cancer effects result from long-term exposure, recent research has found “that biochemical responses are occurring at lower levels of benzene exposure than previously known.”³¹⁵

2. Toluene

While there is not yet adequate information to classify toluene as a human carcinogen, it does cause serious neurological and developmental effects.³¹⁶ For example, central nervous system (“CNS”) dysfunction and narcosis have been “frequently observed” in humans acutely exposed to toluene by inhalation, even in low levels.³¹⁷ In more chronic exposures with high levels of toluene, CNS depression has occurred, resulting in symptoms such as “ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision.” Chronic inhalation has also caused non-CNS effects such as “irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep.”³¹⁸ And developmental effects have occurred in the children of women who have abused toluene during pregnancy.³¹⁹

In studies of occupational exposures to toluene, “neurological effects (i.e., impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) [were] the most sensitive endpoint.”³²⁰

³¹² See Stuart Batterman, University of Michigan, for Sierra Club, *Health Effects of Hydrogen Sulfide Exposures: A Review of the Evidence Pertaining to Low Level Exposures* 5-6 (2012) [hereafter Batterman, *Hydrogen Sulfide Exposures*] (on file with Petitioners); Hydrogen Sulfide, Community Right-to-Know Toxic Chemical Release Reporting, 76 Fed. Reg. 64,022, 64,024-25 (Oct. 17, 2011).

³¹³ *RIA* at 4-9.

³¹⁴ *Id.* at 4-15.

³¹⁵ *Id.*

³¹⁶ *Id.* at 4-16.

³¹⁷ *Id.*

³¹⁸ *Id.*

³¹⁹ *Id.*

³²⁰ *Id.*

3. Ethylbenzene

In acute exposure to humans, ethylbenzene has been found to result in respiratory effects such as throat irritation and chest constriction, as well as neurological effects such as dizziness.³²¹ In cases of chronic exposure, ethylbenzene “may cause eye and lung irritation, with possible adverse effects on the blood.”³²² Although there is not yet ample human evidence to demonstrate the carcinogenic and developmental effects of ethylbenzene, animal studies have found both, and the International Agency for Research on Cancer has classified ethylbenzene as “possibly carcinogenic” to humans based on animal studies.³²³

4. Xylenes

Although EPA has found xylenes to be “not classifiable with respect to human carcinogenicity,” effects via acute inhalation include “irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects.”³²⁴ Chronic effects via inhalation include nervous system effects such as “headaches, dizziness, fatigue, tremors, and impaired motor coordination.”³²⁵

5. n-Hexane

Exposure to n-hexane includes a variety of effects to the nervous system, which is the chemical’s primary target via inhalation.³²⁶ Limited data exists with respect to oral exposure to n-hexane. Effects via acute exposure include “dizziness, giddiness, slight nausea, and headache,” and effects via chronic exposure include “numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue.”³²⁷ As with xylenes, EPA has classified n-hexane as “not classifiable as to human carcinogenicity” due to limited human data.³²⁸

In summary, it is certain that the oil and gas extraction industry—by its admission and EPA’s previous conclusions—has involvement with, uses, and releases a large number and range of toxic chemicals listed under the TRI. This alone strongly weighs in favor of adding the industry sector to the TRI. As EPA has stated: “[a]ssociation with section 313 listed toxic chemicals suggests that facilities within industry groups should be covered under EPCRA section 313, given the purpose of EPCRA section 313 is to provide information to the public about toxic chemicals in their communities.”³²⁹

³²¹ *Id.* at 4-17.

³²² *Id.*

³²³ *Id.* at 4-17-4-18.

³²⁴ *Id.* at 4-18.

³²⁵ *Id.*

³²⁶ *Id.* at 4-18.

³²⁷ *Id.* at 4-19.

³²⁸ *Id.*

³²⁹ 61 Fed. Reg. at 33,594.

6. Hydrogen Sulfide

As noted above, EPA recently lifted an administrative stay and has reinstated hydrogen sulfide as a chemical for reporting to the TRI, based in particular on chronic health effects in humans and adverse effects in aquatic organisms.³³⁰ Hydrogen sulfide is a “broad-spectrum toxicant” that is primarily absorbed through the lungs and can also be absorbed through the gastrointestinal tract and the skin.³³¹ The primary tissues affected are those with exposed mucus membranes, such as the eyes and nose, and those with a high oxygen demand, such as the lungs and brain.³³²

Hydrogen sulfide is most well-known for its acute effects resulting from short exposures of high concentration.³³³ Indeed, these exposures are “among the most common causes of sudden death in the workplace,” and hydrogen sulfide “is the second most common cause of fatal gas inhalation exposures in the workplace.”³³⁴ Among the reported locations in which deaths have been caused by hydrogen sulfide are “oil and gas well drilling sites.”³³⁵ Primary toxic effects include “knockdown”—i.e., acute central neurotoxicity—pulmonary edema, conjunctivitis, and olfactory paralysis. Accompanying secondary effects of hydrogen sulfide toxicity are headaches, memory loss, and acute and chronic respiratory effects.³³⁶

While more is known about the acute effects than chronic effects of hydrogen sulfide, due to “poor exposure characterization” in observational studies and feasibility concerns in controlled studies, such chronic effects underlay EPA’s decisions to add and reinstate the chemical to the TRI.³³⁷ As described by EPA, “hydrogen sulfide can reasonably be anticipated to cause serious or irreversible chronic human health effects,” and these effects include upper respiratory tract toxicity—specifically nasal lesions—and neurotoxicity.³³⁸ “Reported neurological effects include incoordination, poor memory, hallucinations, personality changes, and anosmia (loss of sense of smell); the respiratory effects include nasal symptoms, sore throat, cough, and dyspnea,” as well as impaired lung function in asthmatics.³³⁹ With the first TRI reporting due in July 2013, more information as to hydrogen sulfide releases will undoubtedly add to our knowledge base.

³³⁰ Batterman, *Hydrogen Sulfide Exposures* at 5-6; 76 Fed. Reg. at 64,024-25.

³³¹ Batterman, *Hydrogen Sulfide Exposures* at 9.

³³² *Id.* (citing Harriet M. Ammann, Ph.D., *A New Look at Physiologic Respiratory Response to Hydrogen Sulfide Poisoning*, 13 J. Hazardous Materials 369 (1986); Marvin S. Legator, *Health Effects from Chronic Low-Level Exposure to Hydrogen Sulfide*, 56 Archives Envtl. Health 123 (2001)).

³³³ *Id.*

³³⁴ *Id.* (citing NIOSH, *Occupational Health Guideline for Hydrogen Sulfide* (1978); Tee L. Guidotti, *Hydrogen Sulfide*, 46 Occupational Med. 367 (1996)).

³³⁵ *Id.* at 9-10 (citing ATSDR, *Toxicological Profile for Hydrogen Sulfide* (2006)).

³³⁶ *Id.* at 9 (citing Tee L. Guidotti, *Hydrogen Sulfide: Advances in Understanding Human Toxicity*, 29 Int’l J. Toxicology 569 (2010)).

³³⁷ *Id.* at 5, 10-11.

³³⁸ 76 Fed. Reg. at 64,024-25; Batterman, *Hydrogen Sulfide Exposures* at 5-6.

³³⁹ *Id.* at 11.

IV. Addition of the Oil and Gas Extraction Sector Readily Meets EPA's "Information" Factor by Increasing Information Made Available to the Public and Fulfilling the Purposes of EPCRA

The information factor considers whether facilities within the candidate industry group could reasonably be anticipated to increase information made available pursuant to EPCRA section 313, or otherwise further the purposes of EPCRA section 313.³⁴⁰ Specifically, "[i]n addressing the 'information' factor, EPA will consider any information that bears on whether reporting by facilities within the candidate industry group could reasonably be anticipated to *increase the information made available pursuant to EPCRA section 313, or otherwise further the purposes of EPCRA section 313.* The information considered for any specific industry group will necessarily vary from industry group to industry group based on the nature of the industry group and what relevant information is available."³⁴¹

As described herein, addition of the oil and gas extraction sector to the TRI undoubtedly will increase information made available to the public as well as furthering the purposes of the TRI, given the large number of facilities that will be subject to reporting requirements and the lack of public information under current federal and state frameworks.

A. Addition of the Oil and Gas Extraction Sector Will Increase Information Made Available to the Public

The current gaps in federal regulation and disclosure rules have left "an informational void concerning the contents, chemical concentrations, and volumes of fluids that go into the ground . . . and return to the surface in the form of wastewater."³⁴² This is due to three primary reasons: (1) there are no adequate federal disclosure requirements for the chemicals involved in the oil and gas industry, particularly with respect to the expanding field of hydraulic fracturing and the various products involved; (2) there are currently very few other comprehensive federal regulations applicable to—and many key exemptions for—the oil and gas extraction industry; and (3) in light of the federal government's failure to adequately regulate the industry, the state laws and regulations that have arisen in this open field are full of gaps and shortcomings.

1. There Exist No Adequate Federal Disclosure Regulations for the Industry

First, as to federal disclosure rules, it has been over fifteen years since EPA considered adding the industry sector to the TRI. According to EPA's analysis, the primary remaining question was in regard to the industry's ability to meet reporting thresholds in light of EPCRA's definition of "facility."³⁴³ As noted herein, the question should be well settled in favor of listing the industry.³⁴⁴ And moreover, since then, the industry has expanded dramatically, with nearly

³⁴⁰ 61 Fed. Reg. at 33,594 (emphasis added).

³⁴¹ *Id.*

³⁴² *House Committee Report* at 4.

³⁴³ 61 Fed. Reg. 33,592.

³⁴⁴ *See* Part IV.B, *infra*.

half a million wells in thirty states by several major companies, and with wells increasingly located in Eastern states in smaller geographic areas.³⁴⁵

Other attempts to add to federal disclosure rules have either failed or are limited. For example, House and Senate Democrats have repeatedly introduced the Fracturing Responsibility and Awareness of Chemicals Act (“FRAC Act”), which would repeal the Safe Drinking Water Act exemption that was enacted in 2005—discussed below—and “[r]equire disclosure of the chemical constituents used in the fracturing process, but not the proprietary chemical formula.”³⁴⁶ Due to heavy Republican opposition, the bill has repeatedly failed even to reach the floor of the House.

Similarly, given that nearly a quarter of all natural gas drilling occurs on federal Bureau of Land Management lands, the Department of the Interior has introduced a proposed rule as to disclosure of chemicals used in such production.³⁴⁷ However, the current proposed rule applies only to hydraulic fracturing and would not provide disclosure related to other chemicals used in oil and gas development. Additionally, it is unclear whether the final rule will provide even the limited level of disclosure included in the proposed rule. According to a high-level staffer at the White House, “there are some pretty significant things within that proposal that need to be fixed and addressed, and we’re going to do that.”³⁴⁸

Finally, in the last year, EPA responded to a petition by Earthjustice under section 21 of the Toxic Substances Control Act.³⁴⁹ While EPA granted the petition in part, it only did so to the extent that EPA would initiate “a proposed rulemaking process using TSCA authorities to obtain data on chemical substances and mixtures used in hydraulic fracturing” from manufacturers and processors.³⁵⁰ To the extent that the petition requested EPA use its authority to gather data on

³⁴⁵ *Natural Gas Annual 2010* at 1, 4, 6.

³⁴⁶ See Press Release, Polis, DeGette, Hinchey Introduce FRAC Act to Ensure Safe Drilling of Natural Gas, Mar. 15, 2011, *available at* <http://polis.house.gov/News/DocumentSingle.aspx?DocumentID=229388>; Fracturing Responsibility and Awareness of Chemicals Act of 2011, H.R. 1084, 112th Cong. (2011), *available at* <http://www.govtrack.us/congress/bills/112/hr1084/text>; see also Abraham Lustgarten, *FRAC Act—Congress Introduces Twin Bills to Control Drilling and Protect Drinking Water*, ProPublica, June 9, 2009, *available at* <http://www.propublica.org/article/frac-act-congress-introduces-bills-to-control-drilling-609>.

³⁴⁷ See Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands, 77 Fed. Reg. 27,691 (May 11, 2012).

³⁴⁸ Mike Soraghan, *White House delaying BLM rule at industry’s request*, E&E News EnergyWire, June 22, 2012 (quoting Heather Zichal, Deputy Assistant to the President for Energy and Climate Change).

³⁴⁹ See Letter from Deborah Goldberg, Earthjustice, to Lisa Jackson, EPA, Re: Citizen Petition under Toxic Substances Control Act Regarding the Chemical Substances and Mixtures Used in Oil and Gas Exploration or Production (Aug. 21, 2011), *available at* <http://www.epa.gov/oppt/chemtest/pubs/petitions.html#petition10>.

³⁵⁰ See Letter from Stephen A. Owens, EPA, to Deborah Goldberg, Earthjustice, Re: TSCA Section 21 Petition Concerning Chemical Substances and Mixtures Used in Oil and Gas

chemicals used in the oil and gas industry for purposes other than hydraulic fracturing, EPA denied this request.³⁵¹ EPA additionally rejected a request to issue a “test rule” requiring manufacturers and processors to conduct toxicity testing of the chemicals.³⁵² While the data gained from the forthcoming rule will no doubt fill some of the industry’s many information gaps, the TSCA rulemaking has a similarly narrow scope to the BLM rule: it will only cover one subset of the industry’s chemicals, will only draw on manufacturer data, and is not meant to gather or provide data specifically on toxic chemical releases. Furthermore, it is far from actually applying to the industry, as EPA has yet to publish even a proposed rule.

In short, while federal disclosure requirements are wholly lacking with respect to the oil and gas extraction industry, and it is unfortunate that this absence of coverage has occurred during the industry’s biggest expansion in decades, the problem can be addressed with swift action by EPA under its TRI authority.

2. Other Federal Regulation of the Industry is Limited

Other current federal gaps, however, are not so quickly fixed and are likely to be long-term if not permanent.

Several of these gaps in coverage are due to statutory exemptions. First, as discussed above, the UIC provision of the Safe Drinking Water Act has long appeared to be the relevant vehicle for regulating the underground injections—and accordant drinking water contaminations—associated with oil and gas wells. EPA long resisted exercising this authority, however, and Congress finally modified the program entirely via the Energy Policy Act of 2005 to exclude “the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities.”³⁵³ In fact, the introduction of the FRAC Act was aimed in part at reversing this exemption, but it has not been successful.

Second, as to the Clean Water Act, the Energy Policy Act also had two considerable impacts. For one, the Clean Water Act has long exempted from definition as a pollutant:

water, gas, or other material which is injected into a well to facilitate production of oil or gas, or water derived in association with oil or gas production and

Exploration or Production (Nov. 23, 2011), *available at*

http://www.epa.gov/oppt/chemtest/pubs/EPA_Letter_to_Earthjustice_on_TSCA_Petition.pdf.

³⁵¹ *Id.* at 2.

³⁵² See Letter from Stephen A. Owens, EPA, to Deborah Goldberg, Earthjustice, Re: TSCA Section 21 Petition Concerning Chemical Substances and Mixtures Used in Oil and Gas Exploration or Production (Nov. 2, 2011), *available at*

<http://www.epa.gov/oppt/chemtest/pubs/SO.Earthjustice.Response.11.2.pdf>.

³⁵³ 42 U.S.C. § 300h(d). Notably, although the exemption express does not apply to the injection of diesel fuels, many production companies have apparently continued to use diesel-based products without repercussions. See *Subcommittee on Energy and Environment Memorandum* at 7-8.

disposed of in a well, if the well used either to facilitate production or for disposal purposes is approved by authority of the State in which the well is located, and if such State determines that such injection or disposal will not result in the degradation of ground or surface water resources.³⁵⁴

Although there was some regulatory logic to this exemption when considered in conjunction with coverage by the UIC program, the Energy Policy Act's further exemption of oil and gas wastes from UIC opened a much wider regulatory gap. The Energy Policy Act additionally redefined "oil and gas exploration and production" to completely exempt all such activities, including construction or otherwise, from coverage by the Clean Water Act's regulation of stormwater pollution.³⁵⁵ Accordingly, the Clean Water Act provides no regulation of contaminated stormwater pollution from well pads.

Third, with respect to regulation of oil and gas extraction wastes under RCRA, the 1980 Solid Waste Disposal Act Amendments did not permanently exempt such wastes, but included a requirement that EPA determine either to regulate "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy" under RCRA Subtitle C (i.e., RCRA's hazardous waste provisions) or that such regulations are unwarranted.³⁵⁶ Pursuant to this directive, EPA determined in 1988 that oil and gas wastes need not be regulated under Subtitle C because: (i) the agency could effectively regulate the wastes under Subtitle D regulations that it would enhance (or "tailor"), and (ii) the agency would strengthen Clean Water Act and Safe Drinking Water Act provisions applicable to oil and gas production.³⁵⁷ Nearly twenty-five years later, this promised "tailoring" of Subtitle D rules has not occurred, and both the Clean Water Act and the Safe Drinking Water Act have gotten weaker with respect to such wastes. Nonetheless, the default Subtitle D regulation of the oil and gas extraction industry remains the regulatory framework with no expectation of EPA action on the horizon.

While a lack of federal regulation of the industry is by no means a prerequisite for addition of the sector to the TRI, it does underline the fact that current information is lacking and that adding the industry to the Inventory undoubtedly will increase such information.

3. State Disclosure Rules are Lacking and Contain Many Loopholes and Gaps

In light of the wholly inadequate federal disclosure rules and the gaps and exemptions in other federal substantive rules that could otherwise reveal such information, it has fallen to the states to implement disclosure requirements for the industry. Unfortunately, these requirements are nonexistent in most states and are far from comprehensive in the states where they do exist. No state requirement contains all necessary parameters for full transparency and public awareness, and most contain gaps and are subject to industry privileges. Moreover, some states

³⁵⁴ 33 U.S.C. § 1362(6)(B).

³⁵⁵ See 33 U.S.C. §§ 1362(6)(B), 1342(l)(2).

³⁵⁶ See 42 U.S.C. § 6921(b)(2).

³⁵⁷ See Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. 25,447, 25,456 (July 6, 1988).

unfortunately have gone further and have actually taken action to prevent the dissemination of information.

As to disclosure requirements, the most recent and comprehensive surveys on such requirements were conducted by the nonprofit organizations—and Petitioners—OMB Watch and NRDC.³⁵⁸ Overall, while the reports note that while hydraulic fracturing now occurs in at least twenty-nine states—six of which contain more than 30,000 wells, and five of which contain between 10,000 and 30,000 wells—*only fourteen states* have enacted laws or promulgated rules establishing disclosure requirements with respect to the chemicals involved.³⁵⁹ And the vast majority of these laws contain exemptions under which companies may withhold a product's chemical makeup as a “trade secret” or “confidential business information” without any required factual substantiation or process to evaluate such claims.³⁶⁰

In assessing the existing disclosure rules and the handful of proposed rules, OMB Watch and NRDC have laid out several elements necessary to an effective state disclosure policy, including: the full disclosure of the chemicals' unique identification numbers, concentrations, and quantity used; limitations to “trade secrets” claims, including a process to substantiate and challenge such claims, and the posting of chemical and monitoring plan information to a public website that can be searched, sorted, and downloaded, well-by-well, chemical-by-chemical, and company-by-company.³⁶¹ As it currently stands, no state rule meets all these factors, and *not a single state* provides chemical disclosure information to the public online in a searchable, downloadable format.³⁶² This alone demonstrates the need for TRI reporting.

Looking into each of these elements individually further details the gaps in state disclosure rules. As to the disclosure of individual chemicals, along with their Chemical Abstract Service (“CAS”) number—the unique identifier for chemicals, which is the global standard and the identification used for the TRI—seven states require such CAS number disclosure for all additives, and an additional three require disclosure only in the case of OSHA-defined “hazardous substances.”³⁶³ As to the concentration and volume of the chemicals, only two states require disclosure of actual concentration for all chemicals, one requires such concentration disclosure only for hazardous chemicals, and *no state* requires the disclosure of the volumes of individual chemicals used.³⁶⁴

A related element is the degree to which trade secret claims exempt the disclosure of chemicals. Of the states with disclosure provisions in place, only six require any documentation at all to claim a trade secret exemption, and a mere two—Wyoming and Arkansas—require

³⁵⁸ See generally *OMB Watch Report*; Matthew McFeeley, NRDC, *State Hydraulic Fracturing Disclosure Rules and Enforcement: A Comparison* (July 2012) [hereafter *NRDC Disclosure Report*], available at <http://www.nrdc.org/energy/fracking-disclosure.asp>.

³⁵⁹ *OMB Watch Report* at 3; *NRDC Disclosure Report* at 7.

³⁶⁰ *OMB Watch Report* at 3, 55-56; *NRDC Disclosure Report* at 12-13.

³⁶¹ *OMB Watch Report* at 3; *NRDC Disclosure Report* at 7-13.

³⁶² *OMB Watch Report* at 3-4, 55-56.

³⁶³ *NRDC Disclosure Report* at 10.

³⁶⁴ *Id.* at 10, Tbl. III.

submission of factual substantiation of the claimed exemption.³⁶⁵ Only three states allow the public to challenge the validity of claimed exemptions, but given that none of the three is a state that requires factual substantiation, there is no basis on which the public can evaluate such claims in the first place.³⁶⁶

As to the provision of information to the public, there is currently *no state* that provides the information in a similar online, searchable, downloadable manner as does the TRI.³⁶⁷ In certain states, the disclosure website is limited in such a way as to allow only certain types of searches—for example, by county rather than other useful parameters, such as by chemical—or to provide only certain limited data or geographic information.³⁶⁸

Other states have implemented their disclosure rules via the industry-designed website, FracFocus, but have in the process limited or thwarted certain provisions of their disclosure rules.³⁶⁹ For example, FracFocus allows the reporting of chemicals' concentration *ranges* rather than exact concentrations—even when state rules require exact concentrations.³⁷⁰ And in other instances, limitations in FracFocus's framework have contradicted state requirements and prevented the uploading of certain required data, such as base fluid type.³⁷¹ More fundamentally, FracFocus is not searchable by chemical or date, does not—and likely will not ever—allow for downloading of the database,³⁷² and has a lackluster record with respect to industry compliance in reporting of wells and chemicals.³⁷³

Finally, unlike the reporting that would be required pursuant to the TRI, state disclosure rules have wholly failed to require disclosure of the chemicals in flowback water.³⁷⁴ As noted above, flowback water is a major waste product that totals millions of gallons per well and contains a variety of toxic chemicals. While certain states have required the reporting of the volume of flowback water, the method of its disposal, and/or the method of onsite storage, no state requires any reporting of the wastewater's chemical constituents.³⁷⁵

³⁶⁵ *Id.* at 12.

³⁶⁶ *Id.* at 13.

³⁶⁷ *OMB Watch Report* at 4.

³⁶⁸ *NRDC Disclosure Report* at 7.

³⁶⁹ *Id.* at 8.

³⁷⁰ *Id.*

³⁷¹ *Id.* at 15 n.19.

³⁷² See Benjamin Haas et al., *Fracking Hazards Obscured in Failure to Disclose Wells*, Bloomberg News, Aug. 14, 2012, <http://www.bloomberg.com/news/2012-08-14/fracking-hazards-obscured-in-failure-to-disclose-wells.html>. “It remains unclear whether the database will ever be downloadable for the general public. [FracFocus director Mike] Nickolaus said that’s ‘not a specific goal of the system.’ Not releasing the database was a prerequisite that companies insisted on before they’d participate, he said.” *Id.*

³⁷³ “Energy companies have failed to list more than two out of every five fracked wells in eight U.S. states from April 11, 2011, when FracFocus began operating, through the end of last year . . .” *Id.*

³⁷⁴ *NRDC Disclosure Report* at 13.

³⁷⁵ *Id.* at 13, Tbl. IV.

While these deficiencies in states' disclosure rules—or the lack of such rules altogether—are troubling enough, some states have actively gone further in the direction of opaqueness and have attempted to keep certain information from the public. In particular, Pennsylvania has come under fire recently for its controversial physician “gag rule.” The rule allows a doctor to obtain otherwise confidential chemical information necessary to treat an affected patient, but also requires that the doctor sign a confidentiality agreement, under which the doctor is legally bound not to share the information with anyone else—including other doctors or, potentially, the patient.³⁷⁶ While a few other states have enacted similar physician laws either prior to or based upon Pennsylvania's, and have encountered varying levels of controversy, the central controversial issues to Pennsylvania's are that the act leaves it up to the production companies to draft the confidentiality agreements, thereby sowing inconsistency and leaving a great degree of power with the companies, and the legally binding nature of such agreements.³⁷⁷ Moreover, a large part of the controversy may be the perceived animus of the Pennsylvania gag rule, as it was included in a broader law that additionally removed the ability of local governments to ban, regulate, or otherwise impose “burdens on oil and gas activities beyond those required by the state.”³⁷⁸

Overall, there exists no adequate, comprehensive framework to ensure information as to toxic chemicals used in oil and gas extraction is made available to the public. Instead, due to overwhelming gaps in federal regulations and federal and state disclosure rules, there is “an informational void concerning the contents, chemical concentrations, and volumes of fluids” used and pollutants released by the industry.³⁷⁹ Addition of the industry sector to the TRI will undoubtedly be an improvement on the existing scheme and accordingly will increase such public information.

³⁷⁶ Susan Phillips, *Pennsylvania Doctors Worry Over Fracking ‘Gag Rule,’* Nat'l Public Radio, May 17, 2012, <http://www.npr.org/2012/05/17/152268501/pennsylvania-doctors-worry-over-fracking-gag-rule>.

³⁷⁷ Scott Detrow, *Fracking Disclosure: Colorado's Compromise Is Pennsylvania's Controversy*, NPR StateImpact, <http://stateimpact.npr.org/pennsylvania/2012/06/07/fracking-disclosure-colorados-compromise-is-pennsylvanias-controversy/>.

³⁷⁸ Petra Chesner Schlatter, *Morrisville Borough joins other municipalities in Act 13 lawsuit, opposition of Marcellus Shale drilling*, Bucks Local News, June 19, 2012, available at http://buckslocalnews.com/articles/2012/06/19/yardley_news/news/doc4fd609c4740a1260956117.txt. As of the finalization of this petition a Pennsylvania appellate court has invalidated the zoning provisions of Act 13 as unconstitutional under the Pennsylvania constitution. See Laura Olson, *Court throws out state zoning for Marcellus Shale drilling*, Pittsburgh Post-Gazette, July 26, 2012, available at <http://www.post-gazette.com/stories/local/marcellusshale/court-throws-out-state-zoning-for-marcellus-shale-drilling-646340>. Gov. Tom Corbett's office has since announced that he has appealed the ruling to the Pennsylvania Supreme Court. Laura Olson, *Pennsylvania officials seek expedited review of Act 13 lawsuit*, Pittsburgh Post-Gazette, July 31, 2012, available at <http://www.post-gazette.com/stories/local/marcellusshale/state-officials-seek-expedited-review-of-act-13-lawsuit-646950>.

³⁷⁹ *House Committee Report* at 4.

B. A Significant Number of Oil and Gas Extraction Facilities Will Meet the TRI Reporting Threshold

When EPA last considered the addition of the oil and gas extraction industry to the TRI, the issue that prevented its addition was the definition of “facility,” and accordingly whether individual facilities in the industry would meet the TRI reporting threshold.³⁸⁰ This is an important consideration for the information factor, since an industry will only increase information if industry facilities will surpass the reporting thresholds.³⁸¹ For the reasons stated herein—including the fact that EPA has since resolved this definitional issue in a similar reporting rule for the industry—it is clear that “facility” need not be limited to individual wells. But no matter the definition, there are a significant number of facilities in the industry that will release TRI-listed chemicals well beyond the annual threshold.

1. The Definition of Facility under EPCRA Extends Well Beyond Individual Oil and Gas Well Sites

EPA’s reasoning for not adding the oil and gas extraction industry to the TRI in its 1996-97 rulemaking was due to its concerns over the definition of “facility.” Despite finding that the oil and gas extraction industry conducts management activities that involve TRI chemicals, EPA “chose to defer adding it to the TRI list on the basis of questions as to how the industry’s smallest units—individual wells—would fit with EPCRA’s definition of “facility.”³⁸² EPA explained:

One industry group, oil and gas extraction classified in SIC code 13, is believed to conduct significant management activities that involve EPCRA section 313 chemicals. EPA is deferring action to add this industry group at this time because of questions regarding how particular facilities should be identified. This industry group is unique in that it may have related activities located over significantly large geographic areas. While together these activities may involve the management of significant quantities of EPCRA section 313 chemicals in addition to requiring significant employee involvement, taken at the smallest unit (individual well), neither the employee nor the chemical thresholds are likely to be met. EPA will be addressing these issues in the future.³⁸³

Section 329(4) of EPCRA defines “facility” as “all buildings, equipment, and other stationary items which are located on a single site or on contiguous or adjacent sites and which are owned or operated by the same person (or by any person which controls, is controlled by, or is under common control, with such person).”³⁸⁴

³⁸⁰ 61 Fed. Reg. at 33,592.

³⁸¹ *Id.* at 33,594.

³⁸² *Id.*

³⁸³ *Id.*

³⁸⁴ 42 U.S.C. § 11049(4); *see also* 40 C.F.R. § 372.3; 63 Fed. Reg. at 6,698.

Judicial interpretation has echoed this broad definition.³⁸⁵ Namely, in *Sierra Club v. Tyson Foods*, the court rejected the defendants' assertion that each building on a chicken production farm constituted a separate "facility," and held instead that the "facility" definition applied to the larger chicken production operation and included every poultry house or litter shed.³⁸⁶ Specifically, the court confronted the term with respect to four separately-owned chicken production operations at issue—each of which consisted of sixteen to twenty-four large chicken houses that were connected by common access roads and owned by the same person that owned the operation.³⁸⁷ Although the defendants maintained that each chicken house should be a facility rather than the entire operation, the court concluded:

Each of defendants' chicken production operations is a facility under this definition. The chicken production operations include multiple chicken houses that are located on single or adjacent sites within a concentrated area. These chicken houses are owned by the same person for purposes of producing chickens. Accordingly, each of defendants chicken production operations is clearly a facility under EPCRA from which ammonia releases must be reported on a site-wide basis.³⁸⁸

The current state of the oil and gas extraction industry, and particularly with the advent of multiple hydraulic fracturing wells concentrated in smaller geographies, fits well within this definition. In Pennsylvania, natural gas production on the Marcellus shale formation has resulted in regular instances of one production company moving into a municipality or similar area and developing and operating a number of wells in close proximity. For example, to name just a few of Pennsylvania's major unconventional oil and gas production companies: Cabot Oil & Gas Corporation owns and operates at least 137 wells within the municipality of Dimock, Pennsylvania, as of December 2011.³⁸⁹ All wells are located within approximately a 3.5-mile radius, with the furthest well 3.59 miles from the estimated center point. In fact, a large number of the wells are co-located in clusters of two to five wells per well site.³⁹⁰

³⁸⁵ See Construction and Application of Emergency Planning and Community Right-To-Know Act of 1986 and Regulations Promulgated Thereunder, 9 A.L.R. Fed. 2d 711 (2006) ("The Act requires reports concerning 'facilities' that emit hazardous or toxic substances and courts have been liberal in including adjacent sites in that term, both in enforcing emergency notification requirements and regular reporting requirements.").

³⁸⁶ *Sierra Club, Inc. v. Tyson Foods, Inc.*, 299 F. Supp. 2d 693, 701-02, 711 (W.D. Ky. 2003).

³⁸⁷ *Id.* at 700.

³⁸⁸ *Id.* at 711. Although Tyson Foods played a role as "integrator," the court did not confront the question as to its responsibility for the four individual operations. *Id.* at 700 n.1. Nor did plaintiff make the argument that the four operations should constitute a single facility under EPCRA. *Id.* at 701.

³⁸⁹ PA DEP, *Marcellus-Only Well Production Data, July – Dec. 2011* (2011) [hereafter *PA DEP Well Data*], available at <https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/DataExports/DataExports.aspx>.

³⁹⁰ *Id.* (via entry of coordinates into Google Earth).

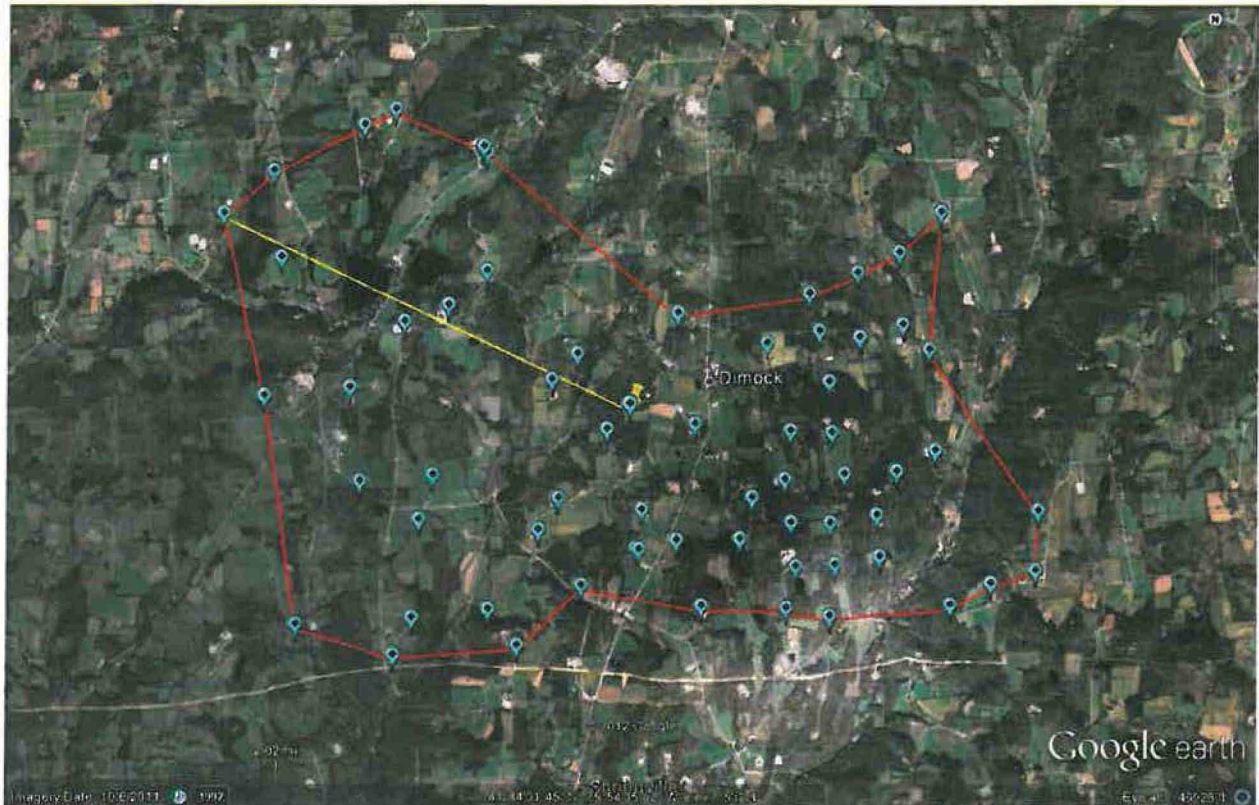


Fig. 1: Well locations of Cabot Oil & Gas Corporation in Dimock, Pa. Each marker may represent up to five wells.

Similarly, Talisman Energy owns and operates at least 174 wells in the municipality of Columbia within approximately a 4.6-mile radius. The vast majority of the wells fall within a four-mile radius of the estimated center point, with the furthest well 4.64 miles from the center.³⁹¹ As with Dimock, a large number of the wells are situated in clusters of two to eight wells. Finally, EOG Resources owns and operates 122 wells in the municipality of Lawrence, within approximately a 3.1-mile radius.³⁹² Like Dimock and Columbia, a number of the well sites contain clusters of two to eight wells.

Such concentration of wells is not solely a Pennsylvania phenomenon. For example, Wyoming's Jonah Field—formally, the Jonah Field Infill Drilling Project Area—contains a relatively small area of productive land: roughly 30,500 acres, of which 14,030 may be disturbed at any one time, with an upper limit of 20,334 total disturbed acres.³⁹³ To put this into comparison, 14,030 acres is equivalent to a circular area with a radius of 2.6 miles, and 20,344 is equivalent to an area with a 3.2-mile radius. The latter is roughly the size of the Lawrence, Pennsylvania drilling area noted above, which contains 122 wells. And yet, Jonah Field currently contains 2,323 wells—with an additional 250 estimated to be developed each year, for

³⁹¹ *Id.*

³⁹² *Id.*

³⁹³ See U.S. Bureau of Land Management, *Record of Decision: Jonah Infill Drilling Project, Sublette County, Wyoming 1* (2006), available at <http://www.blm.gov/wy/st/en/info/NEPA/documents/pfo/jonah.html>.

an upper limit of roughly 3,600 wells.³⁹⁴ The single owner and operator with the largest amount of wells is Encana Oil and Gas USA, Inc., with 1,743 wells.³⁹⁵ These are clearly much more closely located than the Pennsylvania wells. In fact, in one township section alone—i.e., one square mile—Encana owns and operates 90 wells.³⁹⁶

In this respect, oil and gas extraction companies own and operate wells and production facilities “on contiguous or adjacent sites” and are concentrated much more than the industry as contemplated by EPA in 1996. And furthermore, these concentrated groups of well sites and related structures are clearly “owned or operated by the same person (or by any person which controls, is controlled by, or is under common control, with such person).”³⁹⁷ For example, Cabot’s operations in Dimock are operated out of a central headquarters in the township, share seven mobile rigs for the drilling of each well, and collectively send their flowback and produced water to “Cabot’s semi-permanent water recycling station in Dimock.”³⁹⁸ This also largely echoes the EIA’s industry-level assessment from 2006 that “gathering” for processing may serve a production area involving “a hundred or more wells.”³⁹⁹

It is therefore notable that EPA recently finalized a rulemaking in which it adopted a broad definition of facilities as applied to the oil and natural gas extraction industry. Specifically, EPA amended its 2009 greenhouse gas reporting rule to add a number of industry sectors to the regulated entities, including the oil and natural gas extraction sector, as identified by the same NAICS codes used herein.⁴⁰⁰ While EPA considered several different approaches, it ultimately opted to use a “hydrocarbon basin” definition, under which:

all petroleum or natural gas equipment on a single well-pad or associated with a single well-pad and CO2EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in §98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas

³⁹⁴ *Id.* at 14; Wyoming Oil and Gas Conservation Comm’n, Oil and Gas Well Data (2012) [hereafter *WOGCC Well Data*] (on file with Petitioners), available at <http://wogcc.state.wy.us/>.

³⁹⁵ See *WOGCC Well Data*, *supra*.

³⁹⁶ *Id.*

³⁹⁷ 42 U.S.C. § 11049(4).

³⁹⁸ Brandi Devine, *Cabot Oil and Gas Recycles Fracking Water*, WBNG-TV, May 31, 2012, <http://www.wbng.com/news/local/Cabot-Oil-and-Gas-Recycles-Fracking-Water-156018115.html>; Energy in Depth, NWPOA’s Cabot Oil & Gas Tour: A Lesson in Shale Gas Safety, <http://eidmarcellus.org/marcellus-shale/nwpoas-cabot-oil-gas-tour-a-lesson-in-shale-gas-safety/10978/>; Cabot Oil & Gas Corp., *An Outstanding Year in Review: 2011 Annual Report 5* (2012), available at http://www.cabotog.com/images/2011_AR_th.jpg.

³⁹⁹ *Natural Gas Processing* at 3.

⁴⁰⁰ See Mandatory Reporting of Greenhouse Gases, 76 Fed. Reg. 73,886 (Nov. 29, 2011) (to be codified at 40 C.F.R. pt. 98).

production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.⁴⁰¹

The rule defines “basin” to mean “geologic provinces as defined by the American Association of Petroleum Geologists [(‘AAPG’)].”⁴⁰² EPA chose the broad, basin-level definition much on the same basis as its concerns in 1996: “because the boundaries for reporting are clearly defined and the approach covers approximately 81 percent of emissions from onshore petroleum and natural gas production.”⁴⁰³ That is, a broad definition of facility would ensure that reporting thresholds are met and that a greater proportion of the industry is reporting.⁴⁰⁴

Indeed, EPA rejected a smaller “well-pad” definition of facility—i.e., the well and “all stationary and portable equipment operating in conjunction with that well”—because the expected emissions would likely be lower than the threshold, thereby resulting in a minority of the industry reporting.⁴⁰⁵ Similarly, EPA considered an alternative smaller “field-level” definition of facility, which would use the same geographic methodology as the “basin-level” definition but would use the Energy Information Administration Oil and Gas Field Code Master in place of the AAPG Geological Province codes. Again, EPA rejected this definition, as its methodology was no simpler than the basin-level definition—i.e., geographic line-drawing—but would result in approximately fifty-five percent of the industry reporting, rather than eighty-one percent.⁴⁰⁶

In applying this greenhouse gas reporting rulemaking to EPA’s addition of the industry to the TRI, three items are of particular note: First, all three possible definitions were larger than the single-well definition that concerned EPA in 1996 and more accurately reflect the current state and integration of the industry’s components. Second, in applying the “facility” definition to the industry, EPA considered the extent to which facilities would meet the threshold under each definition and chose among the definitions to maximize facility reporting. And third, the rulemaking has already laid much of the groundwork for EPA to take back up the question under EPCRA. What was a technical concern in 1996 has now mostly been resolved.

To this end, EPA has recently proposed addition of two industry groups excluded in 1996-97—as noted above—on the basis of subsequent resolution or reconsideration of previous excluding factors similar to the oil and gas “facility” definition.⁴⁰⁷ For example, with respect to iron ore mining, EPA excluded it from its addition of the metal mining industry in 1997 because

⁴⁰¹ 40 C.F.R. § 98.238.

⁴⁰² *Id.*

⁴⁰³ See Mandatory Reporting of Greenhouse Gases, 75 Fed. Reg. 18,608, 18,615 (April 12, 2010) (to be codified at 40 C.F.R. pt. 98).

⁴⁰⁴ *Id.*

⁴⁰⁵ *Id.* The “equipment operating in conjunction with the well” included “drilling rigs with their ancillary equipment, gas/liquid separators, compressors, gas dehydrators, crude oil heater-treaters, gas powered pneumatic instruments and pumps, electrical generators, steam boilers and crude oil and gas liquids stock tanks.” *Id.*

⁴⁰⁶ *Id.*

⁴⁰⁷ See Part II.D, *supra*.

“[b]ased on the information available to EPA, listed toxic chemicals do not appear to be ‘processed’ or ‘otherwise used’ above de minimis concentrations, nor does it appear that listed toxic chemicals are coincidentally manufactured above the ‘manufacturing’ threshold during the extraction or beneficiation of iron ores.”⁴⁰⁸ However, as EPA has noted in its recent TRI industry scope rulemaking, these “reasons [] may no longer be applicable,” and EPA is accordingly reconsidering adding iron ore mining to the TRI.⁴⁰⁹

Similarly, EPA excluded nonmetal mining, including phosphate mining, from the 1997 additions “based on the belief that the majority of activities conducted by facilities operating in these industry groups are believed to involve materials that are not EPCRA section 313 listed chemicals.”⁴¹⁰ At least partly on the basis of two petitions from Greater Yellowstone Coalition, EPA is now reconsidering whether to add the industry and require reporting “for toxic chemical constituents of phosphate ore and waste rock, as well as for chemicals used or produced coincidentally in beneficiation operations.”⁴¹¹

In short, although EPA exclude the oil and gas extraction industry in 1996 on the basis that the “facility” definition may apply to the smallest component due to the dispersed geographic locations of oil and gas extraction operations, this is not currently the case. Moreover, EPA has already found a workable solution in its greenhouse gas reporting rulemaking, and EPA now has an ideal opportunity to resolve this issue once and for all. Large, concentrated groups of well sites owned and operated by a single company are now common across the United States. The “facility” definition should properly apply to such integrated operations rather than individual wells in order to accurately apply to the state of the industry, maximize reporting to the TRI, and serve EPCRA’s informational goals.

2. A Significant Number of Oil and Gas Extraction Facilities Surpass the Annual Threshold and Would Be Required to Report to the TRI

As a further matter, even if this proper application of the term were not the case, current oil and gas extraction facilities emit, discharge, and otherwise release amounts of toxic chemicals well above the annual reporting thresholds for a variety of TRI-listed chemicals and across several environmental media of release.

⁴⁰⁸ 62 Fed. Reg. at 23,859.

⁴⁰⁹ EPA, Iron Ore Mining, <http://exchange.regulations.gov/topic/trisectorsrule/iron-ore-mining>.

⁴¹⁰ 61 Fed. Reg. at 33,592.

⁴¹¹ EPA, Phosphate Mining, <http://exchange.regulations.gov/topic/trisectorsrule/phosphate-mining>; Greater Yellowstone Coal., *Petition to add Phosphate Rock Mining to the list of facilities required to report releases of chemicals under Standard Industrial Classification Code 1475, or North American Industrial Classification System 213392* (2009), available at <http://exchange.regulations.gov/topic/trisectorsrule/library>; Greater Yellowstone Coal., *Petition to add Phosphate Rock Mining to the list of facilities required to report releases of chemicals under Standard Industrial Classification Code 1475, or North American Industrial Classification System 213392* (2006), available at <http://exchange.regulations.gov/topic/trisectorsrule/library>.

a. Air Emissions above the Reporting Thresholds

The amount of TRI-listed toxic chemicals emitted by the industry and individual facilities within the industry is unquestionably beyond the threshold for a variety of chemicals. For example, under the recently finalized air rule for the oil and gas industry, including the extraction industry and the transmission industry, EPA estimates that the combined rules will directly reduce emissions of HAPs—nearly all of which are TRI-listed chemicals⁴¹²—by 12,000 tons per year, emissions of methane by 1.0 million tons per year, and emissions of VOCs by 190,000 tons per year.⁴¹³ These reductions alone are larger than the *total* annual air releases of many industry sectors, including coal mining, metal mining, fabricated metals, and transportation equipment,⁴¹⁴ which makes it all the more notable that the reductions represent only a small subset of the industry's total HAP emissions: specifically, around 9.6 percent.⁴¹⁵ On this basis, as has been noted above, it appears that the industry's *overall* HAP emissions would be around 127,000 tons per year.⁴¹⁶ Comparing this again to the annual air releases of other TRI-reporting industry sectors, the oil and gas extraction sector ranks well above every other sector, with the exception of Electric Utilities, NAICS Code 2211.⁴¹⁷ In fact, the sector's HAP emissions compare at roughly 29.5 percent of the total air releases of all TRI-reporting sectors in 2010.⁴¹⁸ Breaking down this amount further, the annual BTEX compounds emitted by the industry are between 8,600 and 21,800 tons per year, depending on the source of their emission.⁴¹⁹

Furthermore, as discussed above, the HAP emissions per individual industry component are also significant. For example, as estimated by EPA, the average well completion releases approximately 1.562 tons of HAPs,⁴²⁰ and the average wellhead continues to leak HAPs at a rate of 0.671 tons per year.⁴²¹ Similarly, the average gathering and boosting components leak 3.10

⁴¹² EPA, TRI Comparative Analysis Tool: Data Dictionary, http://www.epa-echo.gov/echo/tricomparative/data_dictionary_tri_comparative_analysis.html (“TRI lists some chemicals as a range of subspecies, not all of which are considered HAPs under the CAA. . . . TRI does not list 6 CAA HAPs: Coke Oven Emissions, Fine Mineral Fibers, Radionuclides (including radon), Isophorone, 2,2,4-Trimethylpentane, and DDE.”)

⁴¹³ *Final Air Rule* at 19 Tbl. 1, 234.

⁴¹⁴ *Id.* at B-8.

⁴¹⁵ See *Proposed Air Rule Fact Sheet* at 1-2. This percentage is based on information EPA provided in its publication of the proposed air rule, which covered a greater proportion of the industry and accordingly achieved over three times the emissions reductions of the final rule. EPA did not provide a similar percentage for the final rule.

⁴¹⁶ However, as discussed above, the average emissions of leaking wells exceeds this estimate almost by a factor of three, which may suggest that this is an underestimate. See Part III.B.2, *supra*.

⁴¹⁷ *TRI 2010 National Analysis* at B-8.

⁴¹⁸ *Id.* at B-1.

⁴¹⁹ *Proposed Air Rule Fact Sheet* at 1; *Gas Composition Memo* at 10 Tbl. 6, 12 Tbl. 9 (using production and well completion weight ratios of BTEX:VOC against total annual VOC emissions).

⁴²⁰ See note 33, *supra*.

⁴²¹ See *Equipment Leak Memo* at 6 Tbl. 2.

tons of HAPs per year, and the average storage component leaks 0.33 tons of HAPS per year.⁴²² As noted above with respect to the Texas emission event data, such estimates are often vastly underestimated by orders of magnitude, but they are notable even as they are.

Additionally noteworthy is the extent of *emission reductions* the final air rule is estimated to achieve on a per-unit basis. While these by no means reflect the entire emissions of each component of the industry, given that the rule does not achieve total reductions or reductions applicable to all emission sources, they are significant. For example, the rule reduces HAP emissions by storage vessels at an average of 2.88 tons per year, by processing plant centrifugal compressors at an average of 0.7 tons per year, and by small glycol dehydrators at an average of 6.8 tons per year.⁴²³

A final dataset that demonstrates the amount of TRI-listed chemicals emitted by oil and gas extraction facilities is the above-noted review of the TCEQ's Emissions Event database.⁴²⁴ Although the dataset is limited to "emissions events" occurring in Texas and is based on industry reporting, which may be underestimated, it still demonstrates that the industry releases a significant amount of HAPs from these events alone.⁴²⁵ For example, between 2009 and 2011, Texas-wide emissions events from the industry released a total 779.01 tons of HAPs.⁴²⁶ And, as discussed above, a few notable data points in particular are the 2009-2011 releases of 17.55 tons, 21.69 tons, and 25.76 tons, respectively, by the Boyd compressor station; a 2011 release of 41.28 tons by a Mont Belvieu fractionator; and 2009-2011 releases of 1.37 tons, 1.12 tons, and 13.82 tons, respectively, by the Dimmit County compressor station.⁴²⁷ The significance of these emission events as TRI releases becomes more apparent when considered in light of the estimated flare efficiency (i.e., chemical destruction) of 98 percent.⁴²⁸ In other words, if an emissions event occurs as a flare, then a factor of fifty times the post-flare emissions is the proper measure of the TRI release.

In short, emissions of HAPs from oil and gas extraction industry sources are significant, and when combined with the remainder of "normal" emissions that make up the vast majority of industry emissions, there is little question that industry facilities would clear the TRI reporting threshold.

b. Chemicals Used in Well Development above the Reporting Thresholds

In addition to the aggregate and individual air data, another factor distinguishing the industry and facilities of today from those in considered by EPA in 1996 is that the well sites in question are vastly different. As discussed in depth above, hydraulic fracturing wells now use 2

⁴²² *Id.*

⁴²³ *RIA* at 3-12 Tbl. 3-2, 3-20 Tbl. 3-4, 3-35 Tbl. 3-9.

⁴²⁴ *See generally Accident Prone.*

⁴²⁵ *Id.* at 1, 3.

⁴²⁶ *Id.*, App. A.

⁴²⁷ *Id.*

⁴²⁸ *Flare Efficiency* at 5; *TRI Instructions* at 60, 63 (requiring reporting of waste treatment efficiency in addition to reporting of chemical released).

to 4 million gallons or more of water and fracturing fluids, produce vast amounts of waste, regularly leave up to eighty to ninety percent of their wastewater underground, and have spills measuring in thousands of gallons.⁴²⁹ Moreover, the increasingly common horizontal well sites are much larger than vertical well sites, and individual well sites commonly contain as many as eight co-located wells.⁴³⁰ That is, even if a company could successfully claim that one well site was the proper measure of “facility,” that well site is now a very different one.

To this end, Petitioner Sierra Club recently undertook an analysis using federal and state agency data to estimate more exact quantities of chemicals used in well development against TRI reporting thresholds. To take just a few chemical uses in well development, it is clear that oil and gas extraction facilities will regularly surpass TRI reporting thresholds.

i. Drilling Muds

To start with the example of drilling muds, the most commonly used weighting agent is barite, which contains TRI-listed metals such as aluminum, antimony, arsenic, beryllium, cadmium, chromium, copper, lead, mercury, nickel, selenium, silver, thallium, and zinc.⁴³¹ With the exception of mercury, the reporting threshold is 10,000 pounds per year, either individually or combined with other listed chemicals.⁴³² Mercury, on the other hand, is specifically listed as a TRI chemical of special concern, for which the reporting threshold is ten pounds per year.⁴³³

⁴²⁹ An issue related to the reporting threshold is the *de minimis* exemption for chemicals in mixtures. See 40 C.F.R. § 372.28(a). Specifically, “[i]f a toxic chemical is present in a mixture of chemicals . . . and the toxic chemical is in a concentration in the mixture which is below 1 percent of the mixture, or 0.1 percent of the mixture in the case of [certain carcinogenic chemicals], a person is not required to consider the quantity of the toxic chemical present in such mixture” when determining the reporting threshold. *Id.* Although EPA has not raised this as an issue for the industry in its 1996-97 consideration or otherwise, industry proponents have often noted that toxic constituents used for fracking are but a small percentage when compared against the combined volume of chemicals and water. Accordingly, it is worthwhile to explain why the exemption would not exempt the industry from reporting the constituents present in fracking fluids and flowback water. As EPA notes in its TRI reporting instructions, “[t]hreshold determinations and release and other waste management calculations begin at the point where the chemical meets or exceeds the *de minimis* level.” *TRI Instructions* at 21. For the typical facility, this point would be triggered prior to the addition of fracking fluids to the millions of gallons of water, and the exemption accordingly would not apply thereafter.

⁴³⁰ Andy Arthur, Google Maps: HVH Marcellus Wells in Pennsylvania. A look at hydrofracked horizontal natural gas wells in Pennsylvania (July 14, 2011) (comparing former vertical well site side-by-side with horizontal well site),

<http://andyarthur.org/fodder/energy/googlemapsprodu.html>; *PA DEP Well Data*.

⁴³¹ EPA, *Proposed Effluent Limitations for Drilling Fluids* at VII-4, VII-6; Argonne National Laboratory, Drilling Waste Management Information System, Fact Sheet: Using Muds and Additives with Lower Environmental Impacts,

<http://web.ead.anl.gov/dwm/techdesc/lower/index.cfm> (internal citations omitted).

⁴³² 30 CFR §372.25.

⁴³³ 30 C.F.R. §372.28.

Data from the U.S. Department of Energy shows that barite specifically contains mercury at 1 part per million (“ppm”) to 10 ppm, depending on the barite’s origin; and EPA’s effluent limitation guidelines for the oil and gas extraction point source category allow the discharge of drilling mud containing barite with up to 1 ppm mercury.⁴³⁴ Accordingly, the calculation herein will assume that the barite contains 1 ppm. Finally, the former Minerals Management Service of the U.S. Department of Interior has estimated that, on average, offshore drilling uses 140 pounds of barite per foot drilled.⁴³⁵ A better estimate for the typical onshore well is 100 pounds per foot drilled.⁴³⁶

Multiplying these numbers with the average onshore natural gas well depth of 6,500 feet, as of 2008, the amount of mercury used per well will be roughly 0.65 pounds.⁴³⁷ In other words, it would take about fifteen wells to exceed the ten-pound threshold. However, as noted above, onshore wells now extend not only 6,000 to 10,000 feet deep, but also include horizontal sections extending typically 1,000 to 6,000 feet in either direction and as long as 10,000 feet.⁴³⁸ Accounting for these longer distances doubles or triples the amount of mercury used and ventures much closer to the reporting threshold.

Similarly, the additional metals present in barite also add up to amounts above TRI-reporting thresholds. As noted above, the reporting threshold for these metals is 10,000 pounds per year, either individually or in combination with other TRI-listed chemicals. EPA data lists the following as the concentrations of TRI-listed metals in barite:

⁴³⁴ See Michael J. Holmes et al., Univ. of North Dakota, Prepared for U.S. Dep’t of Energy, *Subtask 1.23: Mercury Removal from Barite for the Oil Industry 1* (2008) (“Most barite contains some mercury, with concentrations varying from as much as 10 mg/kg to less than 1 mg/kg, based on its location of origin.”), available at <http://www.osti.gov/bridge/servlets/purl/986898-PMvu9b/986898.pdf>; 40 C.F.R. §§ 435.13, 435.15, 435.43, 435.45.

⁴³⁵ Minerals Mgmt. Service, *Estimate of Annual Metric Tons of Mercury Discharged with Barite 1* (2004), available at <http://www.gomr.boemre.gov/homepg/regulate/environ/Hg%20discharge%20estimate.pdf>.

⁴³⁶ See Harvey Consulting, to Delaware Riverkeeper Network & Damascus Citizens for Sustainability, *Delaware River Basin Commission (DRBC) Consolidated Administrative Hearing on Grandfathered Wells 34* (2011), available at http://66.147.244.96/~damascu5/wp-content/uploads/2011/12/Harvey-Report_R1.pdf.

⁴³⁷ See EIA, *Average Depth of Crude Oil and Natural Gas Wells* (release date Sep. 7, 2012), http://www.eia.gov/dnav/pet/pet_crd_welldep_sl_a.htm. Figure reached using this equation: (1 ppm Hg in barite)*(100 lbs barite/ft drilled)*(6,500 ft) = 0.65 lbs Hg.

⁴³⁸ See OMB Watch Report at 11.

Table 4: TRI-Listed Metal Concentrations in Barite.⁴³⁹

Metal	Concentration (ppm)
Aluminum	9,070
Antimony	5.7
Arsenic	7.1
Beryllium	0.7
Cadmium	1.1
Chromium	240
Copper	18.7
Lead	35.1
Nickel	13.5
Selenium	1.1
Silver	0.7
Thallium	1.2
Zinc	201

Using these concentrations against the same figures against the onshore estimate of 100 pounds of barite per foot drilled, there would be a total of roughly 4,800 pounds of these metals in a well of 5,000 feet, 9,600 pounds in a well of 10,000 feet, and 14,400 pounds in a well of 15,000 feet. Considering that an average well may be 6,500 feet deep and a similar distance horizontally, one well could easily surpass the TRI reporting threshold of 10,000 pounds.

ii. Methanol

Another TRI-listed chemical used by the oil and gas extraction industry in large amounts is methanol. In fact, as noted above, methanol was the most widely used chemical identified in the House Committee Report, and individual Marcellus wells have been estimated to use and release over 26,000 pounds of methanol annually across several environmental media.⁴⁴⁰ Like the metals in barite, methanol is listed as a TRI-reportable chemical, with a reporting threshold of 10,000 pounds per year, either individually or combined with other listed chemicals.⁴⁴¹

Methanol is used for a number of applications, but most commonly for gas hydrate inhibition, gas dehydration, gas sweetening, and to recover heavy hydrocarbons.⁴⁴² In applications to inhibit the formation of hydrates, methanol is injected into the well, piping, or gathering lines, thereby preventing the freezing of hydrates at low temperatures.⁴⁴³ In fact, EPA has reported that some operators are forgoing the use of glycol dehydrators altogether, and instead are wholly relying upon injecting methanol into the gas gathering lines, typically at an

⁴³⁹ EPA, *Proposed Effluent Limitations for Drilling Fluids* at VII-6 (internal citations omitted).

⁴⁴⁰ See *House Committee Report* at 6; *N.Y. DEC Revised DSGEIS* § 1.1.1.1.

⁴⁴¹ 30 CFR §372.65.

⁴⁴² See, e.g., Keith A. Bullin & Jerry A. Bullin, *Optimizing Methanol Usage for Hydrate Inhibition in a Gas Gathering System*, Proc. of 83 Gas Processors Ass'n Ann. Convention 1, 2 (2004); Alejandro Esteban et al., *Exploit the Benefits of Methanol*, 79 Proc. Gas Processors Ass'n Ann. Convention 1 (2000).

⁴⁴³ See Bullin, *supra*, at 2.

injection rate of 3 gallons per million cubic feet of gas (gal/MMcf).⁴⁴⁴ Other sources have reported injection rates more commonly at 5 to 15 gal/MMcf and 6 to 41 gal/MMcf.⁴⁴⁵

According to the EIA, the average natural gas well produces roughly 54.2 MMcf/yr.⁴⁴⁶ Using the lowest of the reported methanol injection rates—3 gal/MMcf—the average gas well would use nearly 1,100 pounds of methanol per year for the purposes of hydrate inhibition, or about a ninth of the threshold.⁴⁴⁷ That is, a facility containing nine such wells or using 9,000 pounds of other reportable chemicals, such as benzene or the metals in barite, would trigger the TRI reporting threshold.

This is significant, but it is also based on the lowest rate of methanol injection. The amount of methanol used vastly increases when the higher rates are employed. For example, a treatment rate of 15 gal/MMcf results in about 5,300 pounds of methanol per year, or more than half the annual threshold. And the highest reported treatment rate of 41 gal/MMcf results in nearly 15,000 pounds of methanol injected, well above the annual threshold. Indeed, in making all these methanol calculations, it must be kept in mind that this is but one use of methanol and that data cited above provides a much higher usage of roughly 26,000 pounds per year.⁴⁴⁸

In this way, it is clear that many if not all of EPA's technical concerns from the 1996 proposed rule have been resolved. Both judicial interpretation and EPA have taken a broader view of the "facility" definition; the industry has grown vastly; and the average well site and facility use TRI-listed chemicals above reporting thresholds. At the very least, EPA should finally examine the issue in detail and make the determination it set out to make in 1996.

C. Addition of the Industry Sector Will Otherwise Further the Purposes of EPCRA Section 313

As stated by EPA, the purposes of the TRI program are: "(1) Providing a complete profile of toxic chemical releases and other waste management activities; (2) compiling a broad-based national database for determining the success of environmental regulations; and (3) ensuring that

⁴⁴⁴ EPA, PRO Fact Sheet No. 205, *Replace Glycol Dehydration Units with Methanol Injection 1* (2011), available at http://www.epa.gov/gasstar/documents/methanol_injection.pdf.

⁴⁴⁵ See Bullin, *supra*, at 6; Hayward Gordon Ltd., *Oil and Gas Industry - Produced Water Chemical Treatment 101* at 4 (2011) ("Treatment concentrations depend on the specific thermodynamic situation but usually range between 5 – 15 gallons per million cubic feet of produced gas for either methanol or ethylene glycol."), available at http://www.haywardgordon.com/documents/PRODUCED_WATER_CHEMICAL_TREATMENT_101.pdf.

⁴⁴⁶ EIA, United States Total 2009: Distribution of Wells by Production Rate Bracket (2010) (listing average gas rate per well per day as 148.5 Mcf), http://www.eia.gov/pub/oil_gas/petrosystem/us_table.html.

⁴⁴⁷ Figure reached via the following equation: (3 gal Methanol/MMcf) * (6.6 lbs/gallon) * (54.2 MMscf/yr) = 1,073 lbs/yr.

⁴⁴⁸ See Part III.D.2.f, *supra* (citing *N.Y. DEC Revised DSGEIS* § 1.1.1.1).

the public has easy access to these data on releases of toxic chemicals to the environment.”⁴⁴⁹ Moreover, as stated by President Clinton, who worked to expand the reach of the TRI to more industrial sectors, the TRI “provide[s] a basic informational tool to encourage informed community-based environmental decision making and provide a strong incentive for businesses to find their own ways of preventing pollution.”⁴⁵⁰

Coverage of the oil and gas extraction industry under the TRI will further all of these purposes. As demonstrated above, public information regarding the chemicals used and released in the industry is remarkably low—more so due to the rapid expansion of hydraulic fracturing. With the expansion of the technique and the accordant access by companies to large formations such as Marcellus shale, many people and communities are encountering oil and gas extraction, its chemicals, and its impacts for the first time. Without the necessary information, they cannot make the decisions for their safety, health, or the future direction of their communities. And, as it stands, with minimal disclosure or substantive laws applicable to the industry, oil and gas companies largely control such information and have no incentive to provide it voluntarily.

Furthermore, without disclosure requirements, oil and gas companies have no incentives to find their own way of preventing pollution, to choose less toxic alternatives, or to do anything other than maximize oil and gas production and address the impacts after they have occurred. Adding the industry to the TRI will change this. Providing the “informational tool” of the TRI reports will add some balance to the current dynamic and will allow individuals, communities, and governments to know the full costs and benefits of the industry and make the appropriate decisions. Ideally, oil and gas companies will make similarly appropriate decisions, knowing that the public has access to full information.

With the advent of hydraulic fracturing, we face a variety new impacts and unknowns, the long-term effects of which we are just beginning to learn. The very least that we can do is to require TRI reporting and, from there, go forward with all information available.


V. Conclusion

Petitioners urge EPA to carefully consider this petition because the growth of the oil and gas extraction industry has increased its environmental impact, making the need for public information on the type and amount toxic chemicals used and released by the industry even more urgent. If the sector met EPA’s factors and qualified as a good candidate for addition to the TRI in 1996, there is simply no question that it does now. By this petition, we request that EPA immediately initiate rulemaking to list the oil and gas extraction sector under the TRI. We also request that EPA publish this petition in the Federal Register.


⁴⁴⁹ 62 Fed. Reg. at 23,836; *see also* 61 Fed. Reg. at 33,592-93.

⁴⁵⁰ 60 Fed. Reg. at 41,791.

Respectfully submitted,



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